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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans	Rulemaking 13-12-010 (Filed December 19, 2013)

ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENT ON ASSUMPTIONS AND SCENARIOS FOR USE IN THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR'S 2016-17 TRANSMISSION PLANNING PROCESS AND FUTURE COMMISSION PROCEEDINGS

Summary

This Ruling requests parties' comments on the attached Assumptions and Scenarios proposed by California Public Utilities Commission (Commission) staff for use in the California Independent System Operator's (CAISO's) 2016-17 Transmission Planning Process (TPP) and future Commission procurement-related proceedings.

As a courtesy and because of the relevance of these Assumptions and Scenarios to renewables planning, this ruling is being served on parties in both this proceeding and the rulemaking (R.) on Renewables Portfolio Standard (RPS) implementation (R.15-02-020). Comments are to be filed only in this proceeding.

Comments may be filed and served by no later than February 22, 2016, with replies due no later than February 29, 2016.

Discussion

Commission staff has coordinated with the California Energy Commission (CEC) and the CAISO staff to recommend the attached Assumptions and

Scenarios. The update to these Assumptions and Scenarios, in response to parties' comments, is proposed to be used in resource planning studies in future Commission proceedings and in the CAISO's Transmission Planning Process.

The proposed update is a comprehensive overhaul of the standardized Assumptions and Scenarios of previous years, though some aspects are unchanged. It includes technical updates to key planning assumptions that incorporate the best available information, as well as recent policy direction, for the CAISO to utilize in its Transmission Planning Process.

Attached to this ruling are the updated Standardized Planning Assumptions. The Scenario Tool Excel Workbook referenced in the attachments will be available on the Commission's website at: http://www.cpuc.ca.gov/LTPP/.

In addition, the RPS Calculator version 6, also referenced in the attachments, is available at http://www.cpuc.ca.gov/RPS_Calculator.

The updated document includes the following key changes:

Demand-side assumptions

- 2015 Integrated Energy Policy Report (IEPR) forecasts for electricity demand, including Additional Achievable Energy Efficiency (AAEE);
- Creation of an alternate load forecast based on doubling of AAEE by 2030, interpolated to 2026.

Supply-side assumptions

- Clarification of which resources should be considered as "existing" or additional to the resource fleet, and how resource retirement dates should be calculated;
- Updated import and export assumptions;

- Updated assumptions for combined heat and power (CHP), dispatchable storage, demand response, and renewable resources.

In addition to updating the modeling assumptions, ten potential scenarios are proposed for modeling. Unlike previous years, this year staff does not propose a "trajectory scenario," which in the past has represented a scenario that forecasts the likely implementation of current energy policy. Instead, staff proposes a default scenario for modeling purposes that sets a common foundation for modeling, but that is not sufficiently correlated to current adopted policy to support a need determination leading to procurement authorization. The default scenario is designed for use in comparison to other scenarios.

Parties are invited to comment on any and all aspects of the attachment and are also requested to respond to the following specific questions in their comments on this ruling:

1. Is a high AAEE trajectory, representing a doubling of AAEE by 2030, as proposed, reasonable? If not, what alternative methodology or AAEE adoption curve would be more reasonable and why?
2. Are updates to the demand-side and supply-side assumptions reasonable and accurate? Please specify any assumptions that should be revised and provide a detailed justification supporting the revision.
3. How should exports be treated for modeling purposes? Should we assume no net exports?
4. Do the ten proposed scenarios provide useful information for decision makers? Are there other scenarios that should be modeled instead or in addition?
5. Assuming not all scenarios will be modeled, in what order of priority should the scenarios be studied?

6. Is using a default scenario based on a 43.3% Renewable Portfolio Standard (RPS) in 2026 and doubling AAEE per Senate Bill 350 by 2030 – but interpolated to a 2026 AAEE amount for 2016 LTPP purposes - reasonable?
7. Is re-using a 2015-16 CAISO TPP 33% RPS portfolio in the CAISO 2016-17 TPP study appropriate? (Staff's intent is to avoid evaluating transmission needs based on speculative resource portfolios.)
8. Are the assumptions to be used in the RPS Calculator to generate RPS portfolios appropriate for each scenario? Why or why not?
9. Are there any additional assumptions, or combinations of assumptions, that would be appropriate to use to generate RPS portfolios for each scenario? Please be specific about each assumption and each combination. Present a detailed justification for any additional assumptions proposed.
10. Is the photovoltaic generation pattern throughout the day adequately captured in the assumptions?
11. What capacity factor should be assumed for behind-the-meter CHP when it is modeled as a "supply-side" resource?

Any party with technical questions on the Attachment to this ruling may contact Carlos Velasquez in the Commission's Energy Division at carlos.velasquez@cpuc.ca.gov or (415) 703-1124.

After review of the comments and replies in response to this ruling, an assigned Commissioner's Ruling will be issued endorsing a final Assumptions and Scenarios Document for 2016 for immediate use by the CAISO.

IT IS RULED that:

1. This Ruling shall be served on parties to Rulemaking 15-02-020.
2. Interested parties may file and serve comments in this proceeding on the attached proposed standardized Assumptions and Scenarios by no later than

February 22, 2016. Parties are requested to include responses to the specific questions outlined in the text of this Ruling.

3. Interested parties may file and serve reply comments by no later than February 29, 2016.

Dated February 8, 2016 at San Francisco, California.

/s/ JULIE A. FITCH
Julie A. Fitch
Administrative Law Judge

ATTACHMENT
DRAFT

Planning Assumptions & Scenarios Update For The 2016 Long Term Procurement Plan Proceeding And The CAISO 2016–17 Transmission Planning Process

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1 Introduction

The California Public Utilities Commission (CPUC or "Commission," hereafter) staff have prepared this 2016 Long Term Procurement Plan (LTPP) Assumptions and Scenarios (A&S) document in collaboration with staff from the California Energy Commission (CEC) and California Independent System Operator (CAISO). This proposal includes ten proposed scenarios which would use four different (Renewable Portfolio Standard (RPS) portfolios.[1] These scenarios, if adopted and studied, would help our agencies test for the overall impact these scenarios' embedded assumptions would have on costs, Greenhouse Gas (GHG) reduction and system reliability measures. This A&S document will be published within the 2014 Order Instituting Rulemaking (OIR) but is expected to be incorporated into the 2016 OIR once that Rulemaking is initiated.

As in previous LTPP cycles, this document provides demand-side and supply-side planning assumptions that should be utilized in the 2016 LTPP and, where appropriate, in the 2016-17 TPP studies. Demand-side assumptions are based on 2015 IEPR demand forecasts, which accounts for transmission and distribution line losses. Additional demand-side assumptions are incorporated into some of the proposed scenarios such as those addressing SB 350 energy efficiency impacts and recently procured in-front-of-the-meter Demand Response (DR).

The supply-side assumptions clarify which resources should be considered "existing" or additional to the resource fleet, how resource retirement dates should be calculated, and the assumptions that should be made regarding capacity and energy contributions of "imported" and "exported" resources. The supply-side assumptions also clarify which renewable resource portfolios would be assumed under the various study cases.

In early 2016, the LTPP Assigned Commissioner, the President of the Commission, and the Chair of the CEC, will send a "transmittal" letter to the CAISO identifying which scenarios our joint agencies recommend should be studied in the Transmission Planning Process (TPP), including a recommendation of which scenario should be studied as the "base-case" in the 2016-17 TPP.

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[1] The four RPS portfolios are: a 33% portfolio that would be used in the 2016-17 TPP studies; a 50% by 2030 portfolio that is fully-deliverable; a 50% by 2030 portfolio that incorporates energy-only projects to reach the 50% RPS target; and a 50% by 2030 portfolio that incorporates 3000 MW of wind resources from Wyoming.

Unlike previous LTPP cycles, this document does not propose a trajectory scenario for the 2016 LTPP. The recent approval of Senate Bill (SB) 350 has made the trajectory of State policy clear on a broad basis, but additional development on specific modeling inputs is needed before a true trajectory scenario can be developed. Instead, we recommend adopting a Default Scenario that can be used to test certain modeling inputs and provide information for the development of a trajectory scenario at a later date. The Default Scenario, however, should not be regarded as representing the most probable California energy future; rather, the Default Scenario should be considered as analogous to a "control group" of assumptions reflecting existing programmatic and energy policies that we will use to compare and contrast the differences between it and the other scenarios.

1.1 Terminology

Acronym	**Definition**
1-in-10	1-in-10 year weather peak demand forecast
1-in-2	1-in-2 year weather peak demand forecast
AAEE	Additional Achievable Energy Efficiency
AB	Assembly Bill
ACR	Assigned Commissioner Ruling
BTM	Behind-the-meter
CAISO	California Independent System Operator
CEC	California Energy Commission
CED	California Energy Demand Forecast (CEC process)
CHP	Combined Heat and Power
CPUC	California Public Utilities Commission or "Commission"
DCPP	Diablo Canyon Power Plant
DR	Demand Response
EE	Energy Efficiency
ELCC	Effective Load Carrying Capability
GHG	Greenhouse Gas
GWh	Gigawatt Hour
IEPR	Integrated Energy Policy Report (CEC process)
ILR	Inverter Loading Ratio
IOU	Investor Owned Utility
ISO	Independent System Operator (same as "CAISO")
LCR	Local Capacity Requirement
LSE	Load Serving Entity
LTPP	Long Term Procurement Plan (CPUC)

MW	Megawatt
MWh	Megawatt Hour
NMV	Net Market Value
NQC	Net Qualifying Capacity
OIR	Order Instituting Rulemaking
OTC	Once-through cooling
PG&E	Pacific Gas and Electric
POU	Publicly Owned Utility
PV	Photovoltaics
RFO	Request for Offers
RNS	Renewable Net Short
RPS	Renewable Portfolio Standard
SB	Senate Bill
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SWRCB	State Water Resources Control Board
TEPPC	Transmission Expansion Planning Policy Committee
TOU	Time-of-Use
TPP	Transmission Planning Process (CAISO)
WECC	Western Electricity Coordinating Council

1.2 Definitions

- **Load Forecast**: refers to the electricity demand served by the electric grid, measured by both peak demand and energy consumption. Load forecasts are influenced by economic, BTM resource assumptions (such as distributed generation), and demographic factors as well as retail rates.
- **Assumption**: a statement that is made regarding the future for a given load forecast, or demand side or supply side energy resource, that should be used for procurement and transmission modeling purposes. For example, a forecasted load condition is an "assumption."
- **Scenario**: a complete set of assumptions defining a plausible California-centric energy future. Scenarios are driven by major factor(s) with impacts across many aspects of loads and resources. For example, a change in the energy load forecast would be considered a new scenario since the change would impact other variables including the amount of renewable projects and possibly transmission needs.

- **Portfolio**: a component of scenarios, portfolios are the mix of resources to be modeled, created as a result of applying the assumptions in a specific scenario. A high distributed generation scenario, for instance, would have a different portfolio of resources than a 33% base case scenario. RPS portfolios refer specifically to the portfolio of supply-side renewable resources in a given scenario.
- **Sensitivity**: a variation on a scenario where only one variable is modified to assess its impact on the overall scenario results. Removing Diablo Canyon Power Plant, while holding other assumptions constant, is an example of a sensitivity. However, changing the energy load forecast would be considered a new scenario rather than a sensitivity since the change would impact other variables including the amount of renewable resources and possibly transmission needs.
- **Managed Forecast**: refers to the California Energy Demand Forecast that has been adjusted to account for the impact of load modifying programs that are expected to come online but that are not embedded into the baseline load forecast. An example of a "managed forecast" is a situation in which we adjust the forecasted load in order to account for energy efficiency programs that are not yet funded but that are expected to be implemented over the course of the planning horizon – frequently referred to as Additional Achievable Energy Efficiency (AAEE).
- **Probabilistic Load Level**: refers to the specific weather patterns assumed in the study year. For example, a 1-in-10 load level indicates a high load event due to weather patterns expected to occur approximately once every 10 years. The probabilistic load level primarily impacts annual peak demand (and other demand characteristics, such as variability) but does not significantly impact annual energy consumption.

1.3 Background

The Long-Term Procurement Plan (LTPP) proceedings were established to ensure a safe, reliable, and cost-effective electricity supply in California.[2] A major component of the LTPP proceeding addresses the overall long-term need for new system reliability resources, including the need for resources that provide operational flexibility.

[2] Pursuant to Assembly Bill (AB) 57 (Stats. 2002, ch. 850, Sec 3, Effective September 24, 2002), added Pub. Util. Code § 454.5., enabling resources to resume procurement of resources. *See also* OIR 3/27/2012, Scoping Memo 1.

Due to the fact that the CAISO's annual Transmission Planning Process (TPP) and the CPUC's LTPP utilize similar planning assumptions, these assumptions should align and be consistent. In order to ensure this alignment and consistency between the LTPP and TPP planning assumptions, the CPUC updates the planning assumptions on an annual basis in coordination and collaboration with the CAISO and the CEC; this document contains those updates. Staff expects that an Assigned Commissioner's Ruling (ACR) will finalize the Planning Assumptions and Scenarios document for 2016.

1.4 History of LTPP Planning Assumptions

Since the 2006 LTPP the CPUC has worked to make the long-term procurement planning process more streamlined and transparent. The main effort of the 2008 LTPP was the creation of the *Energy Division Straw Proposal on LTPP Planning Standards*.[3] The 2010 LTPP took strides towards implementing that proposal, with adjustments based on party comments. CPUC Energy Division staff held several workshops in the summer of 2010, and in December of that same year, the *2010 LTPP Standardized Planning Assumptions* were issued via a Joint Scoping Memo and Ruling.[4] Following a similar process of workshops and comments in 2012 and 2013, the CPUC established LTPP planning assumptions for the 2012 and 2014 LTPP that build upon previous planning efforts to further improve the LTPP process.

2 Guiding Principles

The Guiding Principles[5] for developing assumptions to be used, and scenarios to be investigated, in the 2016 LTPP Rulemaking are:

A. **Assumptions** should take a realistic view of expected achievements from established policies while exploring potential impacts from possible policy changes.

B. **Assumptions** should reflect real-world possibilities, including the stated positions or intentions of market participants.

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[3] *Energy Division Straw Proposal on LTPP Planning Standards*, http://docs.cpuc.ca.gov/published/Graphics/103215.PDF

[4] *See* Assigned Commissioner and Administrative Law Judge's Joint Scoping Memo and Ruling, issued December 3, 2012, http://docs.cpuc.ca.gov/EFILE/RULC/127542.htm

[5] *See* Assigned Commissioner's Ruling on Standardized Planning Assumptions, R.12-03-014, issued June 27, 2012.

C. **Scenarios** should be informed by an open and transparent process. An exception is confidential market price data, which may be reasonably submitted with publicly available engineering or market-based price data checked against confidential market price data for accuracy.

D. **Scenarios** should inform the transmission planning process and the analysis of flexible resource requirements to reliably integrate and deliver new resources to loads.[6]

E. **Scenarios** should be designed to contain useful policy information, for example tracking greenhouse gas reduction goals, and reliability implications of existing and expected resource procurement policies.

F. **Resource portfolios** should be substantially unique from each other.

G. **Scenarios** should be limited in number based on the policy objectives that need to be understood in the current Long Term Procurement Plan cycle.

H. Resource planners including the CPUC, CEC, and CAISO, should strive to reach agreement on planning assumptions, and commit **to transparent, consistent, and coordinated planning processes.**

3 Planning Scope: Area & Time Frame

The following assumptions and scenarios are created specifically with regards to the loads served by, and the supply resources interconnected to, the CAISO-controlled transmission grid and the associated distribution systems.[7] The LTPP planning period forecasts 20 years out in order to study the impacts of major infrastructure decisions under consideration. The long term nature of resource planning is necessary given that resources procurement decisions typically take 7-9 years until fruition. While detailed planning assumptions are used to create an annual loads and resources assessment in

[6] Scenarios used by the CAISO Transmission Planning Process must meet the requirements in Section 24.4.6.6 of the CAISO's tariff. Scenarios developed in the LTPP process may inform the development of the CAISO's TPP scenarios to the extent feasible under the CAISO tariff and adopted by that organization.

[7] The technical studies will model the entire Western Electricity Coordinating Council (WECC); this document describes the assumptions that should be used for the balancing areas located inside the CAISO service territory. For assumptions pertaining to the balancing authorities located outside of the CAISO service territory, use the latest TEPPC Common Case data.

the first 10 -year period (2016-2026), more generic long-term assumptions are used in the second 10-year period (2027-2036), reflecting the greater uncertainties associated with forecasting a more distant future.[8] Nonetheless, each LTPP cycle considers the shorter-term (present to 10 years out) implications that infrastructure policy decisions have in conjunction with the longer term (10 to 20 year out) implications that each decisions carries.

This document supersedes the previous versions of assumptions and scenarios in this proceeding.

4 Planning Assumptions

A description of assumptions is provided in this section. All values will be reported in the 2016 Scenario Tool, a spreadsheet developed by CPUC staff to quantitatively present the load and resource assumptions for each of the scenarios described in this document. The most recent version is 2016 Scenario Tool version 1.[9]

4.1 Demand-side Assumptions

4.1.1 Baseline, Incremental, and Managed Forecasts

The LTPP uses the CEC-adopted California Energy Demand Forecasts (CED)[10] as its "baseline" forecast. Demand-side assumptions are either embedded in the baseline forecast or consist of adjustments made to the baseline forecast. Incremental resource projections, such as AAEE,[11] are not embedded in the baseline forecast, but can be used to modify the baseline forecast to create a net or "managed" forecast. As an example, in the CED the CEC embeds an amount of energy efficiency representing current codes

[8] The updates incorporated in this document will also inform the 2016-17 TPP studies.

[9] The Scenario Tool to be used in conjunction with the 2016 LTPP assumptions and scenarios is being updated. It will be posted on the CPUC LTPP webpage.

[10] See the CED: California Energy Demand 2016-2026 Forecast, http://www.energy.ca.gov/2015_energypolicy/

[11] The AAEE projections: Estimates of Additional Achievable Energy Savings, Supplement to California Energy Demand 2016-2026 Forecast, https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-05

and standards and established energy efficiency programs. AAEE represents future expected energy and capacity savings from programs not yet established or funded; as such, AAEE is considered an incremental resource projection to the Energy Efficiency (EE) embedded in the CED. In addition to its "baseline" demand forecast, the CEC publishes managed load forecasts which embed different levels of AAEE assumptions.

For modeling purposes the CEC provides its AAEE savings projections at the transmission bus-bar level to the ISO; this information offers AAEE locational specificity to the ISO and is provided on yearly basis for the given TPP's 10-year planning horizon.

4.1.2 Locational Certainty

As California chooses to meet its electricity needs with increasing proportions of demand-side management resources, such as energy efficiency and customer-sited solar photovoltaic (PV) self-generation, it becomes increasingly important to accurately forecast the locations of these demand-side impacts in order to capture the benefits that these resources provide to the system. Reliability studies in transmission-constrained local areas depend on these demand-side resources being capable of providing capacity value within the electrical areas in which they are forecasted to be located; ideally, their capacity value and location would be forecasted at specific transmission-level bus-bar or substation locations so that they can offset local capacity requirements in these subareas. Historically, demand-side resource projections lacked the locational certainty needed to contribute to local reliability. Fortunately, the current California Energy Demand set of forecasts, with its embedded demand-side resources and incremental AAEE projections, is increasingly incorporating greater locational certainty by providing impacts at the climate zone level for BTM resources. The CEC defines 15 climate zones in California.[12] Efforts are underway to further refine the locational certainty of all BTM demand-side resources, to the transmission substation level, so that the capacity benefit provided by these resources can be appropriately counted on as a potential alternative to local conventional generation. [13]

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[12] See p. 51 of http://www.energy.ca.gov/2013publications/CEC-200-2013-004/CEC-200-2013-004-V1-CMF.pdf

[13] For the past three TPP cycles, the CEC staff have developed load bus projections of AAEE peak savings to enable the CAISO to include these savings in its power flow studies. These "translations" of the approved AAEE projections, for use in the TPP, are not explicitly adopted by the CEC.

4.1.3 Load

The CEC's 2015 Integrated Energy Policy Report (IEPR), which includes the California Energy Demand (CED) forecasts, serve as the source for the "managed demand forecasts;" it consists of a base load forecast coupled with several alternative AAEE projections (see subsection on Energy Efficiency below). The CED base forecasts include three load cases, "Low," "Mid," and "High," each factoring in variations on economic and demographic growth, retail electricity rates, fuel prices, and other elements. Each load case also has peak demand weather variants, for example, 1-in-2 weather year and 1-in-10 weather year. The 2016 LTPP Scenarios incorporate the "Low" and "Mid" load cases.

While the CED forecast use the best available information, they do not include all future expected activity. For example, the 2015 CED base forecast does not include the impact of the CPUC's recently adopted rate changes. Additionally, the 2015 CED does not incorporate changes expected to result from the adoption of Senate Bill 350, since the legislation was passed too late in the process to revise forecasts.

The 2015 IEPR CED forecasts does account for the electrification of the transportation sector. However, development of policies that drive higher electrification growth is underway and may result in a different level of penetration of electric vehicles (EVs) across all vehicle types, including rail electrification, than what is embedded in the 2015 IEPR base load forecast.

The CEC issued revised CED base 1-in-2 weather adjusted forecasts on December 17, 2015, and is expected to publish the full, adopted, forecast in early 2016.

For planning studies that utilize an 8760 hour load profile as input, the load profile should have annual peak and energy values consistent with the CED forecast for the year being studied. The base load profile should be adjusted by using CEC-provided AAEE load shapes described in the following subsection. For planning studies that utilize a single historical year as the basis for 8760 hour load shapes, the historical year should match the year used in the TEPPC 2026 Common Case.[14]

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[14] The TEPPC 2024 Common Case used the year 2005 as the basis for load shapes because it reflected an average weather year. TEPPC is considering using 2009 as the basis for load shapes in the 2026 Common Case.

4.1.4 Energy Efficiency

Energy efficiency forecasts are developed from the CEC's 2015 IEPR CED base forecasts and its supplemental AAEE projections. Each load case of the CED base forecasts contains an embedded EE component that will be paired with an AAEE projection scenario representing additional savings. CEC staff, with input from the Demand Analysis Working Group and in consultation with CPUC staff and CAISO staff, developed the AAEE projections. In general, the lowest savings scenario includes only the EE savings most certain to materialize while the highest savings scenario includes all EE potential including aspirational goals (e.g. emerging technologies). Depending on the type of planning study, finer granularity of EE savings projections may be required.

Some planning study types may utilize EE savings projections allocated at the transmission-level busbar, and/or daily and seasonal load-shape EE savings projections. The CEC is developing 8760 load shapes for AAEE that match to the aggregate AAEE projections documented as part of the revised demand forecast. This task was undertaken so that modelers will not have to make up their own hourly shape, or debit it from peak and annual energy, and then effectively apply the same shape to AAEE as they do for the base forecast. We require that modelers use these 8760 hourly load reduction values when submitting studies to the CPUC, CEC or the CAISO. Transmission and distribution loss-avoidance effects shall be accounted in all studies.

The 1-in-2 weather year, Mid Baseline-Mid AAEE forecast, should be used for the CAISO's system-wide 2016-17 TPP cycle[15] and for the CPUC's 2016 LTPP flexibility studies. The Mid Baseline-Low AAEE forecast should be used for local reliability studies. The Low AAEE scenario is appropriate for local reliability studies given the difficulty of forecasting load and AAEE at specific locations.

In order to approximate the AAEE envisioned by SB 350, the preliminary AAEE amount to comply with SB 350 should be calculated using the following steps, below.[16] (Unlike

[15] This would be done using the "Infrastructure Investment Scenario" – see scenario #2 in section 5.1 "2016 Planning Scenarios."

[16] This calculation represents Commission staff's preliminary calculation that is necessary to make based on our proposed 2016 LTPP Scenarios. We look forward to CEC directives explaining how to calculate SB 350 AAEE mandates more accurately once the CEC has adopted a SB 350 AAEE by 2030 methodology.

the AAEE forecasts, mentioned above, the preliminary SB 350 AAEE calculation must to be based on the 2014 IEPR CED forecast.[17]):

1) Download Form 1.1c[18] – Statewide, California Energy Demand Updated Forecast, 2013 - 2025, Mid Demand Baseline Case, **Mid AAEE** Savings, Electricity Deliveries to End Users by Agency gigawatt-hours (GWh). This spreadsheet includes yearly, 2013 to 2025, GWh breakout by Load Serving Entity (LSE).[19] Apply the LSE specific "Average Annual Growth 2014 – 2025" found in column P of this same Form 1.1c in order to extrapolate the GWh of "Electricity Deliveries to End Users by Agency" for the un-forecasted years (2026 to 2030), for each LSE, of the Mid Demand Baseline Case, Mid AAEE Savings forecast.

2) Download Form 1.1c[20] – Statewide, California Energy Demand Updated Forecast, 2013 - 2025, Mid Demand Baseline Case, **No AAEE** Savings, Electricity Deliveries to End Users by Agency (GWh). This spreadsheet also includes yearly, 2013 to 2025, GWh breakout by LSE. Apply the LSE specific "Average Annual Growth 2014 – 2025" found in column P of this same Form 1.1c in order to extrapolate the GWh of "Electricity Deliveries to End Users by Agency" for the un-forecasted years (2026 to 2030), for each LSE, of the Mid Demand Baseline Case, No AAEE Savings forecast.

   ***Note:** both these spreadsheets are identical/symmetrical; that is, PG&E's bundled customers' relevant Mid AAEE and No AAEE forecasted amounts in 2018, for instance, can be found in the same cells on both spreadsheets, making it easy

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[17] "The commission shall base the targets on a doubling of the midcase estimate of additional achievable energy efficiency savings, as contained in the California Energy Demand Updated Forecast, 2015-2025, adopted by the commission, extended to 2030 using an average annual growth rate…" P.U. Code Section 25310(c)(1).

[18] Found on the CEC's website, here: 2014 IEPR Load Forecast Directory; LSE and BA Tables Mid Demand Baseline-Mid AAEE.xls;

[19] This preliminary SB 350 AAEE calculation only includes the load of CPUC jurisdictional LSEs: PG&E, SCE and SDG&E bundled load; PG&E, SCE and SDG&E Direct Access load; and Marin Clean Energy CCA and Sonoma Clean Power CCA load, which is in PG&E's service territory.

[20] Found on the CEC's website, here: LSE and BA Tables Mid Demand Baseline-No AAEE.xls

to derive the GWh "delta" between the Mid AAEE and No AAEE forecasts for each LSE in the CAISO service territory, for each year 2013 to 2030, on a different spreadsheet.

3) On a separate spreadsheet subtract the "Mid AAEE" GWh amount from the "No AAEE" GWh amount associated with each LSE in the CAISO territory for each year 2016 to 2030. The result in each cell will equal the GWh AAEE amount that is embedded in the Mid Demand Baseline-Mid AAEE IEPR forecast associated with the given LSE, for each year (2016 to 2025), and for the extrapolated GWh AAEE amounts corresponding to the un-forecasted years (2026 to 2030). See **Appendix A-1**.

4) Apply the incremental growth factors, below, to the 2019 to 2030 GWh results per step #3, for each LSE in CAISO's service territory – this will provide the "doubling effect" per the SB 350 mandate by 2030. See **Appendix A-2**.

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1.05	1.06	1.07	1.08	1.09	1.1	1.2	1.33	1.45	1.6	1.75	2.0

5) The sum total for each LSE in the CAISO service territory in year 2026 will result in the 2026 AAEE assumption used in the 2016 LTPP that is associated with the SB 350 AAEE mandate, and used in Scenarios #1 and #3 – #10. See the graph included in **Appendix A-3**[21] (the two tables at the top of Appendix A-3 also include aggregate results from Appendix A-1/A-2, respectively). **Appendix A-4**, row 67, specifies the annual SB 350 AAEE percentage, based on this preliminary calculation, relative to forecasted/extrapolated load growth in 2016 – 2030 that includes no AAEE.[22]

[21] "Other CAISO" category indicated in the top two tables of Appendix A-3 include of the IOUs' Direct Access load and PG&E's CCA customer load.

[22] That is, with no AAEE embedded in these LSEs combined load forecasts, their total load would be 230,313 GWh in 2030 (see row 65 of Appendix A-4); accounting for our preliminary SB 350 AAEE trajectory, this GWh total would be 67,995 GWh less (row 66), representing a load decrease of 29.52% pursuant to the SB 350 AAEE mandate. For 2026 (and for the 2016-2026 LTPP), however, this SB 350 AAEE GWh amount is 33,114, representing 15.08% of would-be load.

The rest of this A&S document relies on the 2015 IEPR CED forecasts which were made available in December 2015 and are expected to be adopted by the CEC in early 2016. California Energy Commission staff also intends to provide an updated allocation of EE savings projections down to the transmission level bus-bar to the CAISO for use in the 2016-17 TPP.

4.1.5 Solar Photovoltaics

The CED forecasts embed the impacts of programs such as the California Solar Initiative. As such, the BTM PV default projection included in this document assumes no change to the BTM PV embedded in the mid-demand IEPR forecast; the mid-demand IEPR forecast incorporates a mid-PV capacity level.

One of our 10 proposed scenarios however – the High BTM PV Scenario – incorporates a high incremental projection of BTM solar PV relative to the default (i.e. mid-PV capacity level) projection. Due to the higher BTM PV penetration, the associated GWh impact of this High BTM PV Scenario effectively lowers the mid-demand IEPR forecast. The high BTM incremental projection included in the High BTM PV Scenario is created as follows:

> 1) Subtract the mid-PV capacity embedded in the mid-demand IEPR forecast from the high-PV capacity embedded in the low-demand IEPR forecast.
>
> 2) Add the capacity differential in #1 to the mid-PV capacity embedded in the mid-demand IEPR forecast.

The high BTM incremental projection would be adjusted for transmission and distribution loss avoidance and would include the expected Megawatts (MW) production at Investor Owned Utility (IOU) system peak and the expected GWh energy production from BTM PV resources for each year of the 2016-2026 timeframe being studied.[23]

Although BTM PV is generally regarded as a demand-side resource, both the CED forecast embedded PV and any incremental amounts could be modeled as supply resources (e.g. as a non-dispatchable resource with a fixed annual energy profile) in resource planning models. Under this modeling convention, the corresponding demand forecast assumptions in the resource planning model would need to be adjusted upward

[23] These adjustments are calculated in the Scenario Tool; transmission and distribution losses can also be found in Table 2 below (Section 4.1.9)

to remove the impact of BTM PV resources, since BTM PV resources would be separately accounted for as a supply-side resource. The appropriate upward adjustment would require adding back the peak reduction and the energy reduction impact of the BTM PV resources to the demand forecast. Production cost modeling often uses this modeling convention (modeling BTM PV as supply resources). Power flow models, such as used in the CAISO's TPP transmission planning studies may or may not use this modeling convention.[24] That is, they may model BTM PV resources as load modifiers, in which case they would model the load-reducing impacts of BTM PV resources.

The BTM PV resource projections described above are forecasts of the installed AC output of these resources, and reflect estimates of capacity contribution during IOU peak periods and annual energy production. The capacity contributions of BTM PV resources during IOU peak periods in different load areas are calculated by multiplying installed AC capacity by the "peak impact factor." In order to calculate the BTM PV resources annual energy production one must multiply the BTM PV resource "capacity factor" by the MW of installed BTM PV resource capacity and multiply the result by 8760 hours. The table below summarizes the IOUs' peak impact factor and capacity factor that should be used in resource planning studies. They are derived from the embedded BTM ("self-generation") PV resource projection for each of the three major IOUs in the mid-demand IEPR forecast.

[24] The CAISO is considering modeling BTM PV resources as supply-side resources in both production cost and power flow models in the coming year. The CAISO may also allocate BTM PV resources to transmission bus-bars in proportion to load for a given load area, but is also discussing with Participating Transmission Owners of the possibility of using a more refined method.

Table 1: Small Solar PV Operational Attributes

Variable	PG&E	SCE	SDG&E	Average of all 3 IOUs
Peak impact factor[25]	0.352	0.382	0.384	0.367
Capacity factor	0.188	0.205	0.202	0.196

The physical configuration of BTM PV resources influences the shape of hourly generation profiles and has material impact on the outcome of resource planning studies that inform the TPP and the LTPP. Two important physical attributes are the PV mounting type and the DC-AC inverter loading ratio. For BTM PV resources, the default assumption for mounting type is fixed-tilt, south-facing. The ratio of panel capacity to inverter capacity is the "DC-AC inverter loading ratio;" a higher loading ratio tends to flatten or clip the production profile of a PV unit. Industry practice for PV installations has been to install a panel capacity larger than the inverter capacity to compensate for de-rate factors such as DC-AC conversions and losses and to maximize economic value. For BTM PV resources, the default assumption for DC-AC inverter loading ratio is 1.2, which is consistent with the assumption used in the Transmission Expansion Policy Planning Committee (TEPPC) 2024 Common Case.[26]

4.1.6 Combined Heat and Power

The CEC traditionally forecasts a "consumption" energy demand forecast and then subtracts onsite self-generation, such as from BTM CHP resources, to compute the net energy for load. The 2016 LTPP BTM CHP resource default projection assumes no change to the CEC's BTM CHP resource projection.

Similar to BTM PV resources, BTM CHP resources are generally regarded as a demand-side resource. As such, CHP resources assumptions that are embedded in the CED forecast, in addition to any forecasted incremental CHP resource amount, will be

[25] Continued growth in PV adoption will likely reduce demand for utility-generated power at traditional peak hours to the point where the hour of peak utility demand is pushed back to later in the day. This means that future PV peak impacts could decline significantly as system performance drops in the later hours. This possibility has not been incorporated into the demand forecast through CED 2015, and such an adjustment to PV peak impacts could significantly affect future peak forecasts.

[26] https://www.wecc.biz/TransmissionExpansionPlanning/Pages/Datasets.aspx

modeled as supply-side resources.[27] Modelers will adjust the load forecast upward, as needed, when using this modeling convention. Doing so maintains a consistent modeling practice that treats the BTM CHP resources as non-dispatchable generators with both capacity value and an annual production profile. Transmission and distribution loss-avoidance effects shall be accounted for.

Absent more specific locational and technology type information for a resource projection, the default shall be to allocate aggregate resource projections to substations on the basis of peak load ratios, and to model capacity value at peak (peak impact factor) as 0.80[28] of installed capacity and annual energy production using a 0.80 capacity factor.

4.1.7 Demand Response

The CED forecasts embed the impacts of load-modifying[29] demand response (DR) programs. These programs are generally non-event-based and/or tariff-based and include existing Time-of-Use (TOU) rates,[30] Permanent Load Shifting, and Real Time Pricing. Supply-side DR programs, which are generally event-based, price-responsive and reliability programs, are treated as supply-side resources (see Section 4.2.5).

There may also be additional DR impacts that need to be explored. For example, a higher EV penetration scenario could lead to both increases and shifts in electric load, which may incentivize the implementation of DR programs that align these load changes with hours where low cost energy is available. Another expected future DR impact may

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[27] Similar to AAEE and BTM PV DGs, the CEC will provide these data to the ISO to facilitate studying the impacts to the transmission system. If sufficient modeling data is not available, BTM CHP resources will be left embedded in the demand forecast.

[28] We assume that the default profile for CHP is flat and set at 0.8 of installed capacity for 8760 hours.

[29] See D.14-03-026 in the Demand Response Rulemaking, R.13-09-011, for further background on “load-modifying” and “supply-side” DR programs.

[30] The latest CED forecasts embed the impact of the TOU rates and periods existing in 2014, as they were forecast in the IOU’s April 2015 load impact reports. These do include: (for residential customers) continuation of the TOU rates existing in 2014, with essentially no growth in participation – no default – and no late-shift in TOU periods; and (for non-res customers) mandatory TOU but no late-shift in TOU periods.

come from defaulting residential customers to TOU rates.[31] Commission staff will collaborate with CEC's staff to facilitate the study of the default residential customer TOU rate impact in the next major CEC IEPR planning cycle.

4.1.8 Energy Storage

Energy storage units shall be modeled as supply-side resources; therefore this document describes the planning assumptions for distribution-connected and customer-side storage, as well as transmission-connected storage, within the "Supply-side Assumptions" section.

4.1.9 Avoided Transmission and Distribution Losses

Demand-side resource projections need to account for avoided transmission and distribution losses when calculating the balance of projected supply and demand. The table below specifies factors supplied by the CEC for accounting of avoided transmission and distribution losses. These factors are applied to the demand-side resource projections in order to determine the avoided supply-side generation replaced by the presence of the demand-side resource.

Table 2: Factors to Account for Avoided Transmission and Distribution Losses

	PG&E	SCE	SDG&E
Peak, distribution losses only	1.067	1.051	1.071
Peak, transmission and distribution losses	1.097	1.076	1.096
Energy, transmission and distribution losses	1.096	1.068	1.0709

4.2 Supply-side Assumptions

All supply-side resource assumptions are solely for planning study purposes. Inclusion or exclusion of a specific project or resource in the planning cycle has no implications on

[31] The CED forecasts embed the impacts from existing TOU rates but do not include potential impacts from TOU rate changes being considered such as default TOU rates and shifting price periods/seasons.

existing or future contracts. To the extent a specific project or resource turns out to not be available, the planning study assumes an electrically equivalent resource will be available. All supply-side resources should be categorized as either a local resource (specific to a local area), a generic system resource, or a non-CAISO resource. At this time, no degradation of resource production over time is accounted for in these planning assumptions.

Resource Representation In Planning Models

A variety of different types of planning studies may use the supply-side resource assumptions described by this document. Production simulation models should use the actual physical resource attributes of the supply-side (as well as demand-side) resource portfolios specified by this document. Power flow (load flow) and stability studies such as those used in the CAISO's TPP should continue current practices of translating actual physical resource attributes into expected resource output levels under the specific conditions being modeled in such studies.

For variable resources such as those relying on wind or solar energy, hourly production simulation models should use 8760 hour generation profiles for modeling production from variable resources. The source of underlying wind and irradiance profiles and method for creating 8760 hour generation profiles should be documented by the modeler. The 8760 hour generation profiles should also be consistent with the resource technologies and locations specified in the renewable resource portfolios specified later in this document.

In the power flow (load flow) and stability studies typical of the CAISO's TPP, a required input is the expected output level of variable resources under the specific conditions being modeled, usually a specific time of day and season. The CAISO has historically relied on either of two mechanisms for calculating the expected output level. One mechanism is to use the 8760 hour generation profiles for variable resources described above and extract the resource output levels corresponding to the time period being studied (e.g. peak, off-peak, partial peak, and light load base cases). The other mechanism is to rely on the historical Net Qualifying Capacity (NQC) of a variable resource (calculated in the Resource Adequacy proceeding using an exceedance methodology) as the basis for the expected output level of a variable resource with similar technological and locational attributes, under the specific conditions being studied. This document provides no further guidelines to modify current practices within the CAISO's TPP for modeling output levels of variable resources. The CPUC is actively considering the use of Effective Load Carrying Capability (ELCC) methods of assigning capacity value to wind and solar resources for system related studies. For 2016-17 TPP modeling purposes the current Resource Adequacy exceedance methodology should continue to be utilized to model output levels of variable resources in the power flow (load flow) and stability studies typical of the CAISO's TPP.

Capacity Representation In The Scenario Tool

Simple annual load and resource tables such as the Scenario Tool Excel workbook described by this document are generally used as an illustrative assessment of system planning reserve margin up to 20 years into the future. The Scenario Tool stacks up the capacity of supply-side resources using the existing or expected NQC of a resource or portfolio of resources for the month of August (since August is the usual month of system peak capacity needs). To the extent that NQC accounting methodologies change in the future, those changes should be reflected in LTPPs subsequent to the current LTPP.

In the Scenario Tool load and resource table, the capacity representation of both existing and new renewable resources is replaced with the portfolio ELCC representation provided as an output of the RPS Calculator Version 6 and later. The simple annual load and resource table should use ELCC methods to represent renewable capacity. Because the CPUC is expected to adopt ELCC methods for establishing the capacity value of variable resources in the near future, it is reasonable for an illustrative assessment of system planning reserve margin up to 20 years into the future to also use these ELCC methods. Historically, the Scenario Tool represented existing renewable capacity with its aggregate August NQC value, and new renewable capacity with an estimated NQC value generated by RPS Calculator Version 5 or earlier. RPS Calculator Version 6 and later does not produce such NQC estimates and instead produces a portfolio ELCC representative of both existing and new renewable resources for a given portfolio. Thus, the 2016 Scenario Tool will remove the NQC representation of existing renewable resources and replace it with the portfolio ELCC representation of both existing and new renewable resources that the RPS Calculator Version 6 or later produces.

4.2.1 Existing Resources

In the 2016 Scenario Tool, the capacities of existing resources are represented by the monthly NQC values found in the 2016 Resource Adequacy compliance year NQC list. The CAISO and CPUC both publish these lists annually on their respective websites. As noted above, the Scenario Tool will represent the capacity value of both existing and new renewable resources using the portfolio (cumulative) ELCC provided as an output of the RPS Calculator Version 6 and later. This means that in the Scenario Tool, the NQC value of both existing and new renewable resources will be replaced with a portfolio ELCC-based representation that covers both existing and new renewable resources.

4.2.2 Conventional Additions

The default values for conventional resource additions 50 MW or larger derive from the list of power plant siting cases maintained on the CEC website.[32] The default values for conventional resource additions smaller than 50 MW derive from other databases maintained by the CEC. The CEC updates these lists several times per year. A power plant project shall be counted if it (1) has a contract, (2) has been permitted, and/or (3) has begun construction. A power plant project that does not meet these criteria may be counted if the staff of the agency with permitting jurisdiction expects the project to come online within the planning horizon.

4.2.3 Combined Heat and Power

Combined Heat and Power resources identified here export electricity to the grid.[33] The default projection for exporting CHP resources assumes that all retiring CHP resources less than or equal to 20 MW that are on the 2016 NQC list would be replaced on a one to-one basis by similar CHP resources; CHP resources that are greater than or equal to 20 MW will be assumed to retire based on the same methodology used for other conventional resources, as reflected in the Scenario Tool.[34]

Absent more specific locational and technological information from which to base CHP resource projection, the default assumption shall result in an allocation of aggregate resource projections that are apportioned to substations on the basis of peak load ratios Combined Heat and Power capacity values should be model at peak (peak impact factor) as 0.80 of installed capacity. Combined Heat and Power resources are assumed to be non-dispatchable by the CAISO.

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[32] http://www.energy.ca.gov/sitingcases/all_projects.html

[33] The Demand-side Assumptions section discusses resources that provide on-site energy and that therefore offset all, or some portion, of the electric consumption that would have otherwise been met from the grid.

[34] That is, they are assumed retired based on a 40 year life cycle, or contract expiration date (whichever is furthest out).

4.2.4 Energy Storage[35]

CPUC Decision (D.)13-10-040 established a 2020 procurement target[36] of 1,325 MW installed capacity of new energy storage units within the CAISO planning area. Of that amount, 700 MW shall be transmission-connected, 425 MW shall be distribution-connected, and 200 MW shall be customer-side. D.13-10-040 also allocated procurement responsibilities for these amounts to each of the three major IOUs.[37] Storage that is operational after January 1, 2010 and no later than December 31, 2024 shall count towards the procurement target. The default planning assumption for new storage capacity shall account for a conservative expected contribution to grid services and reliability from the storage procurement target in D.13-10-040. For the purposes of the 2016 LTPP it is assumed that there will not be further growth in new storage capacity, post 2024, beyond 1,404 MW (1,325 MW in addition to the 79 MW extra of BTM energy storage that SCE procured via its 2014 Local Capacity Requirements (LCR) Request for Offers (RFO)).[38]

Assumptions about storage attributes and capabilities

While all storage can provide energy services, that is, storage can charge during periods of low energy prices and discharge during periods of high energy prices, their ability to provide capacity and flexibility (load-following, ancillary services, etc.) depends on their visibility and controllability by the CAISO. Transmission-connected storage will likely interconnect to the system near transmission substations and be visible and controllable by the CAISO. Therefore, all of the 700 MW of new transmission-connected storage described above is assumed to provide capacity and flexibility as a default.

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[35] Note that all of the 25 MW of transmission-connected storage represented by SDG&E's required LCR procurement should count as capacity in power flow studies because this storage is expected to be procured specifically to satisfy local capacity requirements. This supersedes the general assumption described that 2-hour storage capacity value should be derated by 50% in power flow studies due to not being able to sustain maximum output for 4 hours per Resource Adequacy accounting rules.

[36] The Decision specifies that resources must be online by 2024 so in the planning assumptions, target amounts are reached in 2024.

[37] The CPUC also established an additional procurement target of 1% of load for ESPs and CCAs. The storage assumptions included herein do not include ESPs' or CCAs' storage resources.

[38] The 79 MW are derived by subtracting SCE's 85 MW customer/BTM storage target from the 164 MW of BTM storage that SCE has procured.

The ability of distribution-connected storage to provide capacity and flexibility carries some uncertainty, in part because this technology is new to the market, and in part because current policy and the CAISO market is still being developed to facilitate the participation of distribution-connected resources.[39] Therefore, similar to the assumption made in the 2014 LTPP, only 50% of the 425 MW of new distribution-connected storage described above is assumed to provide capacity and flexibility as a default. This acknowledges that greater than zero percent but less than 100% of these resources are expected to provide such services.

The ability of customer-side storage to provide capacity and flexibility carries similar uncertainty as distribution-connected storage. However, SCE's 2014 LCR RFO resulted in 164 MW BTM storage, 135 MW of which will provide "4-hour" storage capabilities; the remaining 29 MW consists of the "Ice Bear" project, a permanent load shifting thermal storage resource that, in power flows studies, should be modeled with a discreet negative load in the amount of -14.32 MW each at Johanna and Santiago 66kV bus. In the 2016 LTPP we therefore assume that 135 MW of new customer-side storage will provide capacity and flexibility as a default.

A limiting factor to the ability of storage to provide capacity during peak demand hours is the duration of sustained output. The CPUC factors in a resource's ability to sustain output for at least four hours during three consecutive days when calculating NQC for Resource Adequacy purposes.[40] Therefore, storage resources that only have a depth of two hours should have their capacity value derated by half (50%) for purposes of power flow reliability studies; this discount factor accounts for the inability of such resources to sustain full output of four hours during the duration of system peak hours. Capacity values in Table 3 below reflect this adjustment.

Note that although there are limits on the amount of storage procurement assumed to provide capacity and flexibility as described above, all 1,404 MWs can provide energy services and will be modeled as such in studies involving production cost simulations. The capacity limitations described above apply to power-flow type studies that are conducted in the CAISO's TPP. Table 3 below describes the assumptions that shall be

[39] See CAISO's metering and telemetry options initiative; the Distributed Energy Resource Provider (DERP) initiative; the Energy Storage & Distributed Energy Resource (DERP) initiative; and the Flexible Resource Adequacy Criteria and Must Offer Obligations (FRACMOO) Phase 2.

[40] See page 32 of http://www.cpuc.ca.gov/NR/rdonlyres/C61CB838-E9BB-4CE2-AEB3-63DB955E2EF8/0/RAWorkshopReport2004.doc

used regarding technical characteristics and for the accounting of the three classes of storage described by D.13-10-040.

Table 3: Storage Operational Attributes

Values are MW in 2024	Transmission-connected	Distribution-connected #	Customer- side
Total Installed Capacity	700	425	279 **
Amount providing capacity in power flow studies	560 *	170 *	135 ***
Amount providing flexibility	700	212.5	135
Amount with 2 hours of storage	280	170	100
Amount with 4 hours of storage	256 ^	170	135
Amount with 6 hours of storage	124 ^	85	0
Charging rate: If a unit is discharged and charged at the same power level, assume it takes 1.2 times as long to charge as it does to discharge. Example: 50 MW unit with 2 hours of storage. If the unit is charged at 50 MW, it will take 2.4 hours to charge. If the same unit is charged at 25 MW, it will take 4.8 hours to charge.			

Distribution-connected energy storage is assumed to provide 50% of its installed capacity for modeling in power flow studies
***** This reflects a 50% derating of capacity value of 2 hour storage due to not being able to sustain maximum output for 4 hours per Resource Adequacy accounting rules.
^ This amount was adjusted down to reflect the assumption that the 40 MW Lake Hodges storage project satisfies the storage target for a portion of SDG&E's share of the target.
** SCE procured 164 MW of BTM energy storage via its 2014 LCR RFO, exceeding its 85 MW BTM energy storage 2020 target; these 164 MW, added to PG&E's and SDG&E's BTM energy storage target (85 MW and 30 MW respectively), results in 279 MW of BTM energy storage expected to be online by 2020.
*** Reflects 135 MW of the 164 MW BTM storage resulting from SCE's 2014 LCR RFO. The remaining 29 MW derive from the "Ice Bear Project," a permanent load shifting thermal storage technology that, in power flows studies, should be modeled with a discreet negative load in the amount of -14.32 MW each at Johanna and Santiago 66kV bus.

In the CAISO's TPP Base local area reliability studies the transmission bus-bar identification numbers, names, etc., included in Tables 4 & 5, below, should be used for locational information regarding energy storage resources located in PG&E's[41] and SCE's

[41] PG&E explained the following in regards to the energy storage resources listed in the "PG&E Energy Storage Resources" table: "The majority of the projects listed did not have completed interconnection studies nor were they included in the CAISO Full Network Model at the time of offer submittal. The list has also not been confirmed with the CAISO. Therefore the list is PG&E's current estimate of the nearest Transmission Point of Delivery / Receipt, nearest

Footnote continued on next page

service territories. It is reasonable to assume that cost-effectiveness requirements applicable to new storage capacity will lead to it being sited at the most optimal locations in order to allow these resources to help satisfy the local area reliability requirement. As CAISO staff identifies transmission constraints in the local areas in the current and future TPP technical studies they will also identify which transmission busses most optimally mitigate transmission constraints. Transmission and distribution (and to the extent still necessary customer-side) connected storage amounts providing capacity and flexibility identified in Table 3, above, will be distributed among the transmission busses which most optimally mitigate transmission constraints within local reliability areas. As such, the identified transmission bus locations are potential development sites for storage and should help inform the procurement of storage resources necessary to meet the storage procurement target.

Table 4: Locational Information for PG&E's Energy Storage Resources: Local Area Reliability Studies

PG&E Energy Storage Resources					
Counterparty (Project Name)	**Point of Interconnection (POI)**	**Approximate Transmission Point of Delivery / Receipt**	**Approximate Nearest Resource ID (ResID)**	**Approximate Bus ID (BusID)**	**MW**
Amber Kinetics (Energy Nuevo)	New 70 kV position in PG&E New Kearney Substation	New 70 kV position in PG&E New Kearney Substation	KERNEY_6_LD1	34480_KEARNEY _70.0_LD1	20
Convergent (Henrietta)	Henrietta Distribution Substation (12kV)	Henrietta 70kV Substation	HENRTA_6_LD1	34540_HENRITTA_70.0_LD1	10
Western Grid (Clarksville)	Clarksville 12kV Substation	Clarksville 115kV Substation	CLRKVL_1_LD1	32264_CLRKSVLE_115_LD1	3
Hecate Energy (Molino)	Molino Transmission (69kV) Substation	Molino Transmission (69kV) Substation	MOLINO_6_LD1	31364_MOLINO _60.0_LD1	10
NextEra Energy (Golden Hills)	Tesla Substation 115kV	Tesla Substation 115kV	TESLA_1_QF	33540_TESLA _115_GUM1	30
Hecate Energy (Old Kearney)	Old Kearney 12kV Substation	PG&E New Kearney 70kV Substation	KERNEY_6_LD1	34480_KEARNEY _70.0_LD1	1
Hecate Energy (Mendocino)	Mendocino 12kV Substation	Mendocino 60kV Substation	MENDO_6_LD2	31300_MENDOCNO_60.0_LD2	1
Yerba Buena Pilot Battery Project	21kV Swift 2102 Feeder (into Swift 21kV Substation)	Swift 115kV Substation	SWIFT_1_NAS (not yet operational)	35622_SWIFT _115_GUNS	4
Vaca Dixon Pilot Battery Project	Vaca Dixon 12 kV Substation	Vaca Dixon 115kV Substation	VACADX_1_NAS	31998_VACA-DIX_115_GUNS	2

Resource ID, and nearest Bus ID, and should not be assumed to exactly denote the final busbar location."

Table 5: Locational Information for SCE's Energy Storage Resources: Local Reliability Studies

SCE Energy Storage Resources

	Project	Storage MW	Product Type	Locational Information
LCR RFO 264 MW	Ice Bear	28.64	ES BTM PLS	N/A
	AES	100	IFOM	**Point of Interconnection:** 230kV bus at the **Bus Name:** ALMITOSW **Bus Number:** 24007
	Stem	85	ES BTM	N/A
	Hybrid Electric	50	ES BTM	N/A

	Project	Storage MW	Product Type	Locational Information
ES RFO 16.3 MW	Stanton Energy Reliability	1.3	RA Only	**Point of Interconnection:** Barre **Bus Name:** BARRE **Bus Number:** 24201
	Western Grid	10	RA Only	**Point of Interconnection:** Santa Clara **Bus Name:** S.CLARA **Bus Number:** 24127
		5	RA Only	

	Project	Grid Domain	MW in Plan	MW Actually Installed	A-Bank Substation	Bus Numbers at the 230kV used by TSP and CAISO
EXISTING SCE STORAGE APPROVED AS ELIGIBLE IN D.14-10-045	Tehachapi Storage	Distribution	8	8	Windhub 220/66	29407
	Irvine Smart Grid-Community Energy Storage	Distribution	0.03	0.03	Santiago 220/66	24134
	Irvine Smart Grid-Containerized Energy Storage	Distribution	2	2	Santiago 220/66	24134
	Irvine Smart Grid-Residential ES Unit	Customer	0.06	0.06	Santiago 220/66	24134
	Large Storage Test	Distribution	2	2	Barre 220/66	24016
	Discovery Museum	Distribution	0.1	0.1	Villa Park 220/66	24154
	Catalina Island	Distribution	1	1	N/A	N/A
	V2G-LA AFB	Distribution	0.65	0.5	TBD	TBD
	Self-Generation Incentive Program	Customer	10.9	9.66	TBD	TBD
	Permanent Load Shifting	Customer	5.3	1.14	TBD	TBD
	Home Batter Pilot	Customer	0.08	0	N/A	N/A
	Distribution Energy Storage Integration 1	Distribution	2.4	2.4	Villa Park 220/66	24154

All energy storage described here is exclusive and incremental to any similar technologies that are accounted for as non-dispatchable DR (e.g. Permanent Load Shifting) embedded within the CEC's CED forecasts.

<u>Adjustments due to actual and expected storage projects</u>

The 50 MW of storage that D.13-02-015 ordered SCE to procure, and the 25 MW of storage that D.14-03-004 ordered SDG&E to procure, are assumed to count towards the D.13-10-040 storage procurement target; they should not be double counted.

The 40 MW Lake Hodges storage project located in the San Diego area counts as an existing resource assumption in the Scenario Tool. This project is assumed to satisfy a portion of SDG&E's share of the D.13-10-040 storage procurement target, and is reflected as doing so in Table 3. SDG&E's 2020 transmission-connected storage target is 80 MW.[42] As such, the 40 MW of Lake Hodges is assumed to satisfy SDG&E's share of 6-hour transmission-connected storage target, which amounts to 16 MW (80MW x 20%, per footnote 42). The remaining 24 MW of the Lake Hodges projects is assumed to fill a portion of the 32 MW of SDG&E's 4-hour transmission-connected storage target.

4.2.5 Demand Response

Demand response, or DR, (generally event-based price-responsive and reliability programs) that can be bid into CAISO market shall be accounted for as a supply-side resource. Decision D.15-11-042 the Commission found that, as of January 1, 2018, DR programs that are unable to bid into the ISO market, and are not embedded in the CEC's load forecasts, would no longer have capacity value and thus would no longer receive resource adequacy credit. As of December 2015, SCE has integrated most of its DR programs into the ISO market, while PG&E and SDG&E have integrated smaller portions of their program portfolios. With D.15-11-042, Commission staff anticipates that the IOUs will integrate their DR programs into the ISO market by the January 1, 2018 deadline. Transmission and distribution loss-avoidance effects shall continue to be accounted for when considering the load impacts that dispatchable DR has on the system. The Load Impact Reports filed with the CPUC on April 1, 2015 serve as the basis for DR planning assumptions included herein.

In all types of system and local area resource planning studies, DR capacity shall be counted using portfolio-adjusted the 1-in-2 weather year ex-ante forecast of monthly load impact. This is consistent with the current DR capacity value calculation practice used in Resource Adequacy program.[43] For the purpose of building load and resource

[42] Commission staff's assumption is that each IOUs transmission-connected storage target will be made up of 20% of 6-hour storage, 40% of 4-hour, and 40% of 2-hour storage.

[43] The RA proceeding is considering using a new methodology to determine their NQC of supply-side DR; if a new methodology is approved in 2016 it should be used to derive supply-side DR NQC values in future LTPP cycles.

tables, DR capacity shall be counted using the portfolio-adjusted 1-in-2 weather year condition ex-ante forecast of August load impact. For the purpose of building detailed profiles of DR load impact in system and local area planning models, DR is assumed available at times of system stress, subject to program operating constraints but not limited to operating hours specified in Resource Adequacy accounting rules. Program operating constraints are obtained from the utilities' Load Impact reports and the tariffs associated with each program.[44] The ex-ante load impacts for the operating hours specified in RA accounting rules, by program, are found in the Load Impact reports. For modeling purposes, programs with operating hours beyond hour ending 18 shall be triggered at $600/MWh and all other programs shall be triggered at $1000/MWh. The 2016 LTPP planning assumptions estimate that approximately 1260 MW[45] would be available to mitigate first contingencies[46] system wide by 2026. The fractions of that 1260 MW that are physically located within local reliability areas would be available to meet local reliability needs for each of those areas. Staff developed this estimate by screening DR projections in the April 2015 Load Impact reports for programs that deliver load reductions in 30 minutes or less from customer notification. Staff used the Load Impact Reports' August 2025 portfolio ex-ante impacts coincident with CAISO system peak, and assumed that the 2025 projection can be used to forecast 2026. Table 6 below identifies for each IOU the programs and capacities that meet this criteria. The 5 MW of DR that was procured pursuant to SCE's LCR RFO (approved, in part, by Decision 15-11-041) is assumed to be incremental to the 935 MW[47] of "first contingency" DR in SCE's territory.

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[44] To access IOU demand response tariffs please click on the following links.
PG&E: http://www.pge.com/en/mybusiness/save/energymanagement/index.page
SCE: https://www.sce.com/wps/portal/home/business/savings-incentives/demand-response/
SDG&E: http://www.sdge.com/save-money/demand-response/overview

[45] 1260 MW equals the total DR capacity that meets the "first contingency" criteria detailed in Table 6.

[46] The 30 minute requirement is based on meeting NERC Standard TOP-004-02. Meeting this requirement implies that programs may need to response in 20 minutes, from customer notification to load reduction, in order to allow for other transmission operator activities in dealing with a contingency event. This denotes system adjustments, including demand response, in preparation for the next contingency after the occurrence of the first N-1 contingency.

[47] 935 MW = 611 MW of base interruptible + 66 MW agricultural pumping + 218 MW residential ac cycling + 40 MW non-residential ac cycling

Table 6: Demand Response Capacity Meeting "First Contingency" Criteria

"First Contingency" DR Program MW in 2024 using 1-in-2 weather year ex ante impacts	PG&E	SCE	SDG&E
Base Interruptible	246	611	1.5
Agricultural Pumping Interruptible	n/a	66	n/a
AC Cycling Residential	59	218	12.8
AC Cycling Non-Residential	2	40	3.4

The CPUC is also expected to approve more than 40 MWs of DR contracts for system RA capacity procured through the pilot Demand Response Auction Mechanism (DRAM) for deliveries from June 1, 2016 through the end of 2016. A second auction will run in 2016 for deliveries starting January 1, 2017 through the end of 2017, for a mixture of system, local and flexible RA capacity. That auction has not yet run, so the minimum procurement target of 22 MWs should be used for 2017. The 2016 planning assumptions should take into account the incremental (i.e. not included in Table 6) DR MWs provided through these procurement efforts to the extent that approval of the contracts coincides with the timing of the analysis.

To the extent technical studies require estimates of DR capacity at individual transmission-level busbars, DR capacity will be allocated to busbar using the method defined in D.12-12-010, or specific busbar allocations provided by the IOUs. CPUC staff expects that the IOUs will provide updated busbar allocations to the CAISO for use in the 2016-17 TPP.

Given the uncertainty as to what amount of DR can be relied upon for mitigating first contingencies, the CAISO's 2014-15 and 2015-16 TPP Base local area reliability studies examined two scenarios, one consistent with the 2012 LTPP Track 4 DR assumptions and one consistent with the 2014 LTPP DR assumptions of available first contingency DR. Staff expects that these same DR assumptions will be updated to be consistent with the latest Load Impact reports filed with the CPUC on April 1, 2015 under R.13-09-011, and included in Table 6 above.

4.2.6 Over-generation

Testimony submitted in the 2014 LTPP Proceeding highlighted the potential for fairly significant amounts (400 – 900 GWh) of over-generation by 2024 under a business-as-usual case, with the highest risk of over-generation in the months of March through May. While the exact amount is disputed, there is consensus that the Commission should act now to evaluate solutions to over-generation. This situation will likely be exacerbated by increased renewable deployment to meet the climate goals in SB 350. Commission staff analysis of economic curtailment provisions in IOU contracts indicates that 80 GWh of pre-paid curtailment will be available in 2016. If all RPS facilities with economic curtailment provisions are paid to curtail 100% of their output, they could collectively reduce 2070 GWh of generation in the months of March through May, during the hours of 8am-6pm when the risk of over-generation is forecast to be highest.

For the 2026 study year, the amount of pre-paid curtailment is forecasted to be 200 GWh and total available economic curtailment in March through May of 2026 is forecasted to be 12,600 GWh[48]. However, curtailing renewable resources runs contrary to the State's climate goals and may not be economically efficient. Staff recommends that the LTPP planning assumptions be modified to assume that over-generation events will rely on pre-paid curtailment as the tool of first choice. The Commission should utilize this tool which ratepayers have already paid for before considering investment in additional resources to provide flexibility. The 80 GWh and 200 GWh of pre-paid curtailment available in 2016, and 2026, respectively, should be included as the minimum estimate (e.g. low case) of available curtailment.
In order to facilitate a future that relies on Integrated Resource Planning, the Commission should continue to evaluate the impacts of various portfolios of flexibility tools on costs, reliability, safety, and GHGs.

[48] This is for illustrative purposes only. There is no expectation that any renewable resource would be curtailed 100% of the time.

4.2.7 RPS Portfolios

Overview

Plausible future portfolios of renewable resources for planning purposes are generated using the Renewable Portfolio Standard (RPS) Calculator, version 6.2. The RPS Calculator is a publicly vetted spreadsheet-based tool. It simulates how load serving entities (LSEs) in CAISO's balancing authority area could procure renewable resources in future years in order to meet their annual RPS compliance targets. Since the RPS Calculator is designed to provide input into CAISO's Transmission Planning Process (TPP), the renewable resources that may be needed for LSEs outside of CAISO to meet their own RPS targets are not represented in the RPS Calculator's output portfolio.

Background: 2016 LTPP

In the 2016 LTPP Commission staff intends to use the RPS calculator to generate a set of portfolios that represent some plausible, and yet significantly different, outcomes. The RPS portfolios are not designed to test the range of RPS outcomes or to test the optimal RPS portfolio. Rather, they are selected to align with the LTPP scenarios and to facilitate the examination of the variables addressed by these scenarios. With this intent in mind, the four proposed RPS portfolios to be used in the 2016 LTPP studies are: a portfolio that is fully-deliverable; a portfolio that incorporates energy-only projects to reach the RPS target; a portfolio that would be used in the 2016-17 TPP studies; and a portfolio that incorporates 3000 MW of wind resources from Wyoming. These portfolios are further described in the "RPS Portfolio Selection" subsection, below.

The RPS Calculator can be used to generate a wide range of renewable resource portfolios depending on the input assumptions and the model settings that are utilized. The model settings include the RPS target being modeled and the timeframe for meeting such target, deliverability status of the projects in the supply curve from which the calculator can select, whether or not new projects that are located outside of California may be selected, and land-use restrictions; input assumptions include the forecasted load data (e.g. low, mid or high), existing and expected resources, resource and transmission costs, and demand side management assumptions. As such, a portfolio that combines a low-demand forecast with a high amount of BTM solar PV penetration, for instance, would result in a smaller RPS portfolio (in terms of MW or GWh of renewable resources) than a high-demand forecast in a scenario that also includes very little BTM solar PV penetration. The latest version of the RPS calculator can be found on the "RPS calculator homepage" of the CPUC website here: http://www.cpuc.ca.gov/RPS_Calculator/

The RPS Calculator's Portfolio Generation Process

The RPS Calculator creates renewable portfolios using an iterative, stepwise process to select generic renewable resources and potential transmission upgrades needed to meet a particular RPS target in a specified future year. In order to generate an RPS portfolio, the RPS Calculator starts with base set of resources consisting of approved power purchase agreements (PPAs) and utility owned generation (UOG). The base set of renewable resources includes both existing resources currently in operation ("existing resources") and planned resources under contract that have not yet come online ("future resources").[49]

Next, a renewable net short (RNS) is calculated as the difference between approved generation and the annual RPS target. In order to fill the RNS, a large set of potential renewable resources located throughout California and the WECC region ("generic" or "proxy" resources) are compared against each other using a calculation that includes several different cost and value elements. The cost and value elements in the RPS Calculator are similar to those in the Net Market Value (NMV) formula used in the "least cost, best fit" (LCBF) evaluation process required for actual procurement in the Commission's RPS proceeding. The NMV of each generic renewable resource is calculated as the sum of the following components: (a) resource cost; (b) transmission cost; (c) integration cost; (d) curtailment cost; (e) energy value; and (f) capacity value. A supply curve of renewable resources is developed by ranking each of the generic projects by their NMV.

Finally, the least-cost resources are selected from the renewable supply curve to fill the renewable net short for that year. The selected "generic" resources are added to the set of approved resources to create a new portfolio. The net short and resource selection process then repeats itself for each year of the simulation until the specified future year is reached.

[49] The CAISO will soon determine how much transmission capacity, in different zones throughout its balancing authority area, is available for use by new generation resources. Those renewable resources that are online at the time of CAISO's determination will be considered "existing resources" in the RPS calculator. The remaining available MW of transmission capacity will help Commission staff determine which contracted renewable projects can be considered "future resources."

Resource costs change over time due to technological innovation, financing, and tax policies. The resource composition of the existing portfolio also affects NMV of potential resources in the supply curve by changing the curtailment costs, capacity value, and energy value based on how much energy and capacity is already being provided by existing renewable resources throughout the year. As a result, the order of resources in the supply curve changes in each annual iteration of the procurement simulation based on the cumulative mix of resources that were selected the previous years. In this way, RPS Calculator selects not just the "least cost" resources, but those resources that offer the "best fit" given what is already present in the portfolio at the time the new resources are selected.

The RPS Calculator includes the ability to model the procurement of transmission upgrades in order to enable access to renewable resources in areas that have transmission constraints. Transmission upgrades are only triggered when the NMV of the bundle of resources that the upgrade makes available, including the cost of the upgrade, is superior to any alternatives. The RPS Calculator uses one of two user-selectable options to further evaluate whether or not to trigger transmission upgrades. Under the "FCDS only"[50] option, the RPS Calculator triggers transmission upgrades such that all selected generic resources have sufficient transmission capacity to be fully deliverable. Under the "FCDS & EO"[51] option, RPS Calculator triggers upgrades only when the net value of fully deliverable resources, accounting for the capacity value and transmission upgrade costs, is greater than the net value of energy only resources without transmission costs.

<u>Inter-Agency Collaboration</u>

The RPS Calculator relies, in part, on data developed by CEC and CAISO as inputs. Critical inputs generated by the CEC include load forecasts, energy efficiency forecasts, and BTM solar PV forecasts from the 2015 IEPR. The RPS Calculator also relies on CEC to provide information about renewable resources owned or contracted by POUs in CAISO territory. The RPS Calculator relies on input from CAISO to represent the available transmission capacity in different areas throughout the state, the limits on the amount of energy-only generation that may be added in different areas without triggering

[50] "Full Capacity Deliverability Status"

[51] "Energy Only"

significant curtailment, and the costs and capacity of certain transmission upgrade projects.

The SuperCREZ[52] boundaries used by the RPS Calculator to divide generic resource potential throughout the state into areas that represent similar transmission constraints and upgrade costs were developed in consultation with CAISO.

<u>RPS Portfolio Selection</u>

Four portfolios have been developed to support the 2016 LTPP scenarios:

1) A portfolio reflecting a California energy future that would comply with SB 350 mandates while analyzing the impacts this mandate would have on reliability concerns, operational flexibility and transmission needs and over-generation resulting from a greater renewable penetration. This portfolio would be modeled as being "fully-deliverable"; that is, its resources would receive a capacity payment, in addition to an energy payment. This portfolio would be used in Scenarios #1, #3, #5-6, and #8-10.

RPS Calculator Assumptions for Default Scenario, Scenario #5-6 & #8-10	
Category	**Assumption**
Test year	2026
RPS Percent	43.3% (on path to 50% by 2030)
RPS Deliverability	Fully Deliverable
Geography	In-State
Load	2015 IEPR Mid
AAEE	2 x 2014 IEPR AAEE Mid interpolated to 2026
Behind-the-meter PV	2015 IEPR Mid
DCPP	Retired in 2024/25

2) An "Energy-Only" portfolio would help planners study the consequences of complying with SB 350 mandates while optimizing existing transmission Infrastructure. Similar the RPS portfolio in the "Default Scenario," the Energy-only portfolio would also help system planners to analyze the impacts this mandate would have on reliability concerns, operational flexibility and transmission needs and over-generation results. This portfolio would incorporate some renewable projects that receive an energy payment but that would not receive a capacity payment; it would be used in Scenario #4.

52 CREZ: "Competitive Renewable Energy Zones"

RPS Calculator Assumptions for Deliverability (Energy-Only) Scenario

Category	Assumption
Test year	2026
RPS Percent	43.3% (on path to 50% by 2030)
RPS Deliverability	Fully Deliverable & Energy Only
Geography	In-State
Load	2015 IEPR Mid
AAEE	2 x 2014 IEPR AAEE Mid interpolated to 2026
Behind-the-meter PV	2015 IEPR Mid
DCPP	Retired in 2024/25

3) A portfolio that gives added weight to Wyoming wind would help grid planners examine the impacts that a scenario that incorporates a lot of out-of-state resources may have on over-generation concerns and the resulting costs and benefits analysis relative to the portfolio used in the Default Scenario. This portfolio would be used in Scenario #7.

RPS Calculator Assumptions for Out-of-state Wind Scenario

Category	Assumption
Test year	2026
RPS Percent	43.3% (on path to 50% by 2030)
RPS Deliverability	Fully Deliverable
Geography	WECC-Wide
Required	3000 MW Wyoming wind
Load	2015 IEPR Mid
AAEE	2 x 2014 IEPR AAEE Mid interpolated to 2026
Behind-the-meter PV	2015 IEPR Mid
DCPP	Retired in 2024/25

4) A portfolio to be used in the 2016-17 TPP studies; Staff recommends reusing the "33% 2025 Mid AAEE" RPS trajectory portfolio used in the 2015-16 TPP studies. It is a fully-deliverable portfolio which was developed using the old RPS calculator, version 5.0. Further explanation of the rationale behind this recommendation is provided in the discussion of scenario #2.

4.2.8 Technical Attributes of Solar PV projects

The physical configuration of solar PV projects influences the shape of their hourly generation profiles and has material impact on the outcome of resource planning studies that inform the LTPP. Two important physical attributes are the mounting-type and the DC-AC inverter loading ratio. Mounting-type includes the following:

- Fixed-tilt: stationary panels tilted, south-facing
- Tracking, 1-axis: panels track the sun on a single axis from East to West

- Tracking, 2-axis: panels track the sun on a dual axis (these projects are rare)[53]

The ratio of panel capacity to inverter capacity is the DC-AC inverter loading ratio and a higher ratio tends to flatten or clip the production profile of a PV project. Industry practice for PV installations has been to install a panel capacity larger than the inverter capacity to compensate for de-rate factors such as DC-AC conversions and losses and to maximize economic value. The aggregate assumptions for mounting-type and inverter loading ratio (ILR) for all future studies within the 2016 LTPP proceeding shall be consistent with the values in Table 7.

Table 7: Contracted Solar PV Capacity (MW) & Capacity-Weighted Average ILR, By Mounting-Type

	PG&E	SCE	SDG&E
Fixed-tilt capacity	2,043	876	395
Fixed-tilt ILR	1.26	1.24	1.29
Tracking capacity	1,406	3,334	938
Tracking ILR	1.28	1.31	1.29

Table 7 summarizes the IOU-contracted solar PV capacity (as of June 2015) for each of the three major IOUs and the capacity-weighted average inverter loading ratio separated by mounting-type.[54] "IOU-contracted" means the project has a CPUC-approved power purchase contract and it can be an existing online project or a project still under development. Because these projects have a CPUC-approved power

[53] Dual-axis tracking solar PV projects represent a tiny portion of tracking projects CAISO-wide, just 12 MW of capacity out of over 5,600 MW of IOU-contracted projects. For simplicity, the tables in this section treat dual-axis projects as if they were single-axis projects.

[54] This data was aggregated from individual project data obtained from the CPUC Energy Division's RPS Contract Database (formerly known as Project Development Status Reports), June 2015 vintage, and data request responses from each IOU that provided physical attribute information for all IOU-contracted projects. Projects that were from these two data sources are either existing online projects or projects in development that are assumed to meet the criteria for "commercial" projects in the RPS Calculator. Some of these projects are in fact IOU-owned. The aggregated data does not identify market-sensitive information about individual solar PV projects.

purchase contract, their physical attributes are known and the projects are likely to be completed successfully.

For planning purposes, studies need to assume a mounting-type and inverter loading ratio for "generic" projects. The trends of mounting-type and inverter loading ratio in the most recent IOU-contracted projects can be used as a proxy for the likely physical attributes of "generic" projects. Table 8 below categorizes IOU-contracted projects by online year and identifies the amount of each mounting-type by capacity and percentage of total capacity.

Table 8: Contracted Solar PV Capacity (MW) Grouped By Mounting-Type & Online-Year

	any year	%	2014 or later	%	2015 or later	%
PG&E						
Fixed-tilt	2,043	59%	1,560	61%	176	17%
Tracking	1,406	41%	1,000	39%	831	83%
SCE						
Fixed-tilt	876	21%	836	21%	525	15%
Tracking	3,334	79%	3,215	79%	3,040	85%
SDG&E						
Fixed-tilt	395	30%	17	3%	17	7%
Tracking	938	70%	552	97%	225	93%
3 IOUs						
Fixed-tilt	3,315	37%	2,414	34%	718	15%
Tracking	5,678	63%	4,767	66%	4,097	85%

The newest projects (online in 2015 or later) tend to consist of tracking mounting-types. Based on this trend, "generic" projects selected by the RPS Calculator shall be assumed 15% fixed-tilt and 85% tracking. There does not appear to be a clear difference in inverter loading ratios for newer vs. older projects. Therefore, "generic" projects shall be assumed to have inverter loading ratios similar to the capacity-weighted average of all IOU-contracted projects. Table 9 below summarizes the mounting-type and inverter loading ratio assumptions for "generic" (i.e. not yet contracted) projects. The percentage represents the share of all generic solar PV projects.

Table 9: Generic Solar PV Project Mounting-Type & ILR Assumptions

	PG&E	SCE	SDG&E
Fixed-tilt % share	15%	15%	15%
Fixed-tilt ILR	1.26	1.24	1.29
Tracking % share	85%	85%	85%
Tracking ILR	1.28	1.31	1.29

It is expected that technical modelers, especially those conducting production cost simulations, need to create 8760 hour annual energy profiles for bulk solar. Profile creation requires three key types of information: an 8760 hour solar irradiance profile varying by location, project installed capacity and location, and the technical attributes of each project. Solar irradiance data can be sourced from public datasets such as National Renewable Energy Laboratory's Solar Prospector[55] or Solar Integration National Dataset Toolkit.[56] Project installed capacity and location are provided by the RPS portfolio created by the RPS Calculator. Again, the technical attributes of bulk solar PV projects are specified by Table 7 and 9, above.

However, there is a potential for the annual energy outcome predicted by the RPS Calculator to be different from the annual energy profiles created by technical modelers and incorporating the technical attributes specified above. This is because the RPS Calculator uses simplified weather and technical attribute assumptions[57] to develop its RPS portfolio that meet a certain annual energy target and satisfy the desired RPS requirement (e.g. 50%). Thus, the technical modeler has several options to rectify this potential misalignment. For consistency purposes the following method is adopted:

> Leave the installed capacity provided by the RPS portfolio unchanged. Create the annual energy profiles incorporating the technical attributes specified in this section and use those profiles as inputs to production cost simulations. This may result in annual energy outcomes somewhat different from what the RPS Calculator predicted (e.g. annual RPS energy percentage ended up at 48% or 52% instead of 50%).

Technical modelers are expected to document all details about how they create 8760 hour annual energy profiles for bulk solar, and how the profiles are used in technical studies (e.g. production cost simulations).

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[55] http://maps.nrel.gov/prospector

[56] http://www.nrel.gov/electricity/transmission/sind_toolkit.html

[57] http://www.cpuc.ca.gov/RPS_Calculator/

4.2.9 Nuclear Retirements

PG&E has not clearly stated if it will complete the relicensing process for Diablo Canyon Power Plant (DCPP); and if PG&E completes the relicensing process, it is not clear whether all licenses and permits will be approved. Additionally, it is not clear that PG&E will be willing to retrofit the plant's cooling technology if the State Water Resources Control Board's policy on cooling water intake structures requires a retrofit of DCPP as a condition for its continued operation.

As a default assumption in the 2016 LTPP, it is assumed that DCPP Unit 1 will be retired on November 2, 2024 and that Unit 2 will be retired on August 20, 2025.[58]

4.2.10 Once-Through-Cooled Technology Retirements

The default assumption is that power plants using once-through cooling (OTC) technology retire according to the current State Water Resources Control Board (SWRCB) OTC compliance schedule or sooner per generation owners' latest implementation plans submitted to the SWRCB.

Moss Landing

The original compliance date for Moss Landing under the OTC compliance schedule was December 31, 2017. However, a settlement agreement signed by Dynegy (the owner of Moss Landing) and the SWRCB staff in October, 2014 extended this compliance date to December 31, 2020 for Units 1 and 2 and Units 6 and 7. This OTC amendment, per the settlement agreement, was approved by the SWRCB on April 7, 2015 and is now in effect. Nonetheless, the path to compliance for all of these units remains unclear. The plant's ownership stated its intent to install technology on Units 1 and 2 which will allow them to continue operating. Therefore, staff assumes that by December 31, 2020 Units 1 and 2 will be successfully retrofitted and that Units 6 and 7 will retire.

4.2.11 Renewable and Hydro Retirement Assumptions

Retirement assumptions are based on a facility's age as a proxy for determining a facility's remaining operational life. Operational history will not be considered in this

[58] See "State Nuclear Profiles" page of the U.S. Energy Information Administration website http://www.eia.gov/nuclear/state/california/

planning cycle. A "Low" level of retirement assumes these resource types stay online unless there is an announced retirement date. A "Mid" level assumes solar and wind resources retire at age 25, other non-hydro renewable technologies retire at age 40, and hydro resources retire at age 70. A "High" level assumes solar and wind resources retire at age 20, other non-hydro renewable technologies retire at age 25, and hydro resources retire at age 50. Note that retirement assumptions based on a facility's age carry a wide range of uncertainty. As a default assumption, renewable and hydro resources are assumed to be on a "Low" level retirement schedule.

4.2.12 Other Retirement Assumptions

Retirement assumptions are also based on facility age as a proxy for determining a facility's operational life. Similarly to renewable and hydro retirement assumptions, the operational history of non-renewable/hydro facilities will not be considered in this planning cycle. A "Low" level of retirement assumes that "Other" resource types stay online unless there is an announced retirement date. A "Mid" level assumes a retirement schedule based on resource age of 40 years or more. A "High" level assumes a retirement schedule based on resource age of 25 years or more. Facilities which have an existing contract that runs beyond their assumed retirement age shall instead be assumed to operate until the expiration of the contract. Thus, a 38 year old facility in the "Mid" level that has a three year contract should be assumed to retire at 41 years once that contract expires. Commission staff will periodically request confidential procurement data from the utilities to screen for such facilities. "Other" includes all resources whose retirement assumptions are not explicitly described above – for example peaker and cogeneration facilities. The default assumption for planning studies is a "Mid" level of retirement for "Other" resources.

<u>"Cold shutdowns" or "Mothballed" Facilities</u>

Generator owners that announce they will shut down their facilities, but which do not send notifications of retirement,[59] will be treated as follows: we will assume that, if economic conditions merit, these facilities could be made operational. As such, they will be considered existing resources, subject to the retirement rules.

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[59] As with what has happened when Calpine announced it would not operate the Sutter Energy Center Plant for the rest of 2016.

Long Beach Peakers

From a technical and operational perspective, the Long Beach peaker plants can remain in operation at least through 2025 due to recent refurbishments. These peaker plants' economic lifespan, however, depends on whether this facility can successfully re-contract once its current contract expires in 2017. The planning assumptions in studies informing D.14-03-004 and the 2015-16 CAISO TPP assumed that the Long Beach Peakers would retire at the end of its current contract. In contrast, the retirement assumption specified in the Rulings on 2014 LTPP planning assumptions dated March 4, 2015 assumed that the Long Beach Peakers would remain online at least through 2025. In order to align with the retirement assumption used in D.14-03-004 and the 2016-17 CAISO TPP, the 2016 LTPP planning assumptions now assume that the Long Beach Peakers will retire by December 31, 2017.

4.2.13 Imports and Exports

For the purposes of load and resource tables, i.e. the Scenario Tool, the default value for imports shall be based on the CAISO Available Import Capability for loads in its control area. This import capability is equal to the CAISO Maximum Imports minus Existing Transmission Contracts (ETCs) outside its control area, and is published on its website annually.[60] For 2016 the total import capability is calculated at 11,665MW. In the Scenario Tool, the 11,665 MW value is used throughout the LTPP planning horizon. An alternative assumption is historical expected imports as calculated by the CEC.[61]

Technical planning studies require a more nuanced approach to accounting for imports. In the 2010 and 2012 LTPP studies the CAISO used a tool to calculate California state and CAISO area maximum imports. That tool calculated import limits for each scenario being studied based on inertia changes in the Southern California Import Transmission (SCIT) area due to increased penetration of renewable resources and retirement of

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[60] 2016 Import Capability Assignment Process Steps 6 and 7; found here: http://www.caiso.com/FASTSearch2/Pages/allresults.aspx?k=import%20capability%20step%206

[61] As described in Appendix D, http://www.energy.ca.gov/2012publications/CEC-200-2012-003/CEC-200-2012-003.pdf

generation resources with inertia. The CAISO will update this tool and use it for the LTPP studies envisioned by this document.

For technical planning studies requiring information about infrastructure, resources, and loads outside of the CAISO area, the latest Transmission Expansion Policy Planning Committee (TEPPC) data should be used; see the TEPPC 2024 Common Case generation table.[62]

Resource planning studies conducted for the 2014 LTPP proceeding were largely based on the CAISO's implementation of the PLEXOS production cost simulation model, which relied on data from a pre-release version of the TEPPC 2024 Common Case. The final version of the TEPPC 2024 Common Case is version 1.5.[63] Any additional modeling conducted to inform the 2016 LTPP proceeding should incorporate the final version of the TEPPC 2024 Common Case (v1.5).

In regards to exports, the LTPP planning assumptions have historically been silent on the potential quantity of exports. The CAISO has, in the past, imposed a modeling constraint of "no net exports." This reflects historical practice, but as the system moves forward with regionalization efforts, further work is required to establish appropriate assumptions on the potential exports in different planning futures. In the 2016 LTPP, we expressly include an assumption that California "may" export energy. Export levels should not be artificially held at "zero" in planning studies. Because exports may be used as a panacea for over-generation, masking the true impact of some policy choices, we caution researchers to be realistic and justify their assumptions on the western grid's ability to absorb California energy. Any analysis constraining net exports to be zero, or very low relative to physical and economic potential, should provide corresponding sensitivity cases in which net exports are substantially less constrained.

4.2.14 Local Minimum Generation Requirement by California Balancing Authority Area

This reliability-driven planning assumption in CAISO studies has been replaced by a modeled system-wide frequency response requirement. According to the NERC BAL-003-1 standard the CAISO needs to meet a 752 MW frequency response requirement. Of the 752 MW total requirement, 50% of it (376 MW) can be met by

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[62] *See* Data/Surveys" at http://www.wecc.biz/committees/BOD/TEPPC/External/Forms/external.aspx

[63] https://www.wecc.biz/TransmissionExpansionPlanning/Pages/Datasets.aspx

hydro resources. It will not be modeled explicitly. The other 376 MW requirement can be met by storage and online combined cycle resources.

For the 1,325 MW CPUC mandatory storage resources, the resources that can provide ancillary services – 600 MW transmission connected and 213 MW distribution connected as assumed in the 2014 LTPP ACR – can meet the frequency response requirement on a megawatt for megawatt basis, up to the available headroom. Each MW of online combined cycle capacity can meet 0.08 MW of the frequency response requirement given that the resource has at least 0.08 MW available head room. The previously modeled 25% (of load) local minimum generation requirement was identified in 2015 as a target for deeper explanation and discussion. The new frequency response-based modeling convention should likewise be explained and discussed before planning assumptions in this area are finalized.

4.2.15 Existing Procurement Authorizations

Planning Assumptions Made With Pending Applications Data

Decision 15-11-041 approved the results of SCE's Local Capacity RFO for the Western LA Basin pursuant to D.13-02-015 and D.14-03-004; a Decision addressing SCE's Local Capacity Requirements RFO for the Moorpark is expected to be issued in 2016. SDG&E filled 500 MW of its 800 MW Track 4 LCR authorization via its power tolling agreement with Carlsbad Energy Center LLC. The complete set of planning assumptions for existing LCR procurement authorizations are specified in Table 10, below, and should be used in the 2016 LTPP studies. These assumptions should also be utilized to inform CAISO TPP studies.

Table 10: Procurement Authorization Assumptions With Pending Applications Data

Decision	Capacity (MW)	Assumed online	Location	Description
D.13-02-015, D.14-03-004	640	2021	Long Beach	Combined cycle gas turbine
	644	2021	Huntington Beach	Combined cycle gas turbine
	98	2021	Stanton	Combined cycle gas turbine
	124	2021	W. LA Basin	Energy efficiency
	5 [64]	2019	W. LA Basin	Demand response
	38	2019	W. LA Basin	Distributed generation solar PV
	135 [65]	2019	W. LA Basin	Battery storage – BTM
	29	2020	W. LA Basin	Thermal storage – BTM
	100	2019	Long Beach	Battery storage – transmission-connected
	6	2021	Big Creek/Ventura	Energy efficiency
	6	2018	Big Creek/Ventura	Distributed generation solar PV
	262	2021	Big Creek/Ventura	Peaker gas turbine
D.13-03-029	300	2016	Pio Pico site	Peaker gas turbine
	13	2014	San Diego	Net capacity increase at "MMC Escondido aggregate"
D.14-03-004, D.15-05-051	500	2018	Encina site	Peaker gas turbine
	25 [66]	2019	San Diego	Battery storage – transmission-connected

[64] D.15-11-041 approved only one contract totaling 5 MW of DR resources, subject to the filing of an amended contract via a Tier 1 Advice Letter. Six contracts totaling 70 MW of DR were denied because they would have relied on natural gas-fired BTM generation, and not renewable technologies; they were deemed incompatible with the loading order and the State's policy to reduce reliance on fossil fuels.

[65] A portion of the 264 MW of storage procured for D.13-02-015 and D.14-03-004 and shown in this table also counts toward achievement of the storage procurement target in D.13-10-040. The 264 MW shown here is listed for completeness, but should not be modeled twice (double counted).

[66] The 25 MW storage amount is listed here for completeness, but should not be modeled twice (double counted); it is part of the D.14-03-004 assumptions and of the D.13-10-040 storage procurement target.

Note that the table above does not encompass the entirety of existing LCR procurement authorizations, mostly because SDG&E has not yet filed an application for the preferred resources portion of its authorization. Pursuant to D.15-05-051, SDG&E's power tolling agreement with Carlsbad Energy Center LLC was amended to reduce the contract capacity from 600 MW to 500 MW; the 100 MW in residual procurement authority resulting from this amendment must now consist of preferred resources or energy storage, thereby allowing that the procurement of preferred resources to exceed the 200 MW minimum – up to 300 MW. Since the portfolio of resources to meet the minimum authorization has not been determined at this time, power flow studies should exclude them. To the extent studies identify an LCR need, the remaining 300 MW of authorized LCR procurement need should be considered before authorizing new resources.

The energy efficiency, demand response, and distributed generation resource assumptions listed in Table 10 above represent incremental LCR procurement and are therefore assumed to be incremental to the other energy efficiency, demand response,[67] and distributed generation assumptions described earlier in this document.

<u>Interaction of LCR procurement and storage target</u>

Some of the storage projects included in the applications that would fill existing LCR procurement authorizations are assumed to satisfy the D.13-10-040 storage procurement target; these storage projects are noted in Table 10. Technical studies shall not double count these resources. Table 3 in the Energy Storage section (4.2.4) of this document does not include any adjustment to reflect how existing LCR procurement authorizations are assumed to satisfy the D.13-10-040 storage procurement target. The Scenario Tool illustrates the available capacity from assumed LCR procurement and reconciles how some of this LCR procurement satisfies a portion of the storage procurement target.

SCE's share of the D.13-10-040 storage procurement target for BTM storage is 85 MW. However, SCE proposes to procure 164 MW of BTM storage via its LCR procurement Application, exceeding its BTM storage target (per D.13-10-040) by 79 MW. Technical studies should therefore assume that SCE's share of the D.13-10-040 storage procurement target for BTM storage is completely filled by its proposed LCR procurement. Note that all of the 164 MW of BTM storage represented by SCE's LCR application should count as capacity in power flow studies because this storage is

[67] The "5 MW 2019 W. LA Basin Demand response" project included in Table 10 is the same 5 MW of incremental DR described in section 4.2.5 and should therefore not be double counted.

expected to be procured specifically to satisfy local capacity requirements – this supersedes the general assumption described in the Energy Storage section that BTM storage would not be able to provide capacity in power flow studies.

SCE's share of the D.13-10-040 storage procurement target for transmission-connected storage is 310 MW. However, SCE proposes to procure about 100 MW of transmission-connected storage in its LCR procurement applications. Therefore technical studies should assume that SCE's share of the D.13-10-040 storage procurement target for transmission-connected storage is partly filled by its proposed LCR procurement of 100 MW and the remaining share of the storage procurement target is 210 MW.

SDG&E's share of the D.13-10-040 storage procurement target for transmission-connected storage is 80 MW. After accounting for existing project Lake Hodges, the remaining share is 40 MW (see the Energy Storage section). However, D.14-03-004 requires SDG&E to procure 25 MW of storage that can meet LCR needs. Therefore technical studies should assume that SDG&E's share of the D.13-10-040 storage procurement target for transmission-connected storage is partly filled by its required LCR procurement of 25 MW and the remaining share of the storage procurement target is 15 MW.

Note that all of the 25 MW of transmission-connected storage represented by SDG&E's required LCR procurement should count as capacity in power flow studies because this storage is expected to be procured specifically to satisfy local capacity requirements. This supersedes the general assumption described in the Energy Storage section that 2-hour storage capacity value should be derated by 50% in power flow studies due to its inability to sustain maximum output for 4 hours per Resource Adequacy accounting rules.

4.3 Other Assumptions

4.3.1 The Second Planning Period

Planning studies which target years within the second planning period (2027-2036) will use simplified planning assumptions. Generally, these assumptions reflect extrapolation of the approaches of the first planning period.

- Net (managed) load growth will be extrapolated using the average, annual compound growth rate from the prior period. Only the net load will be extrapolated (i.e. the forecast load, after demand side adjustments such as AAEE), rather than extrapolating individual load or demand assumptions. The formula for calculating the growth rate is:

$$GrowthRate = \left(\frac{NetLoad_{2026}}{NetLoad_{2016}}\right)^{\frac{1}{(2026-2016)}} - 1$$

where Net Load is the gross load forecast minus AAEE. This annual growth rate is then applied to the 2026 Net Load to calculate the Net Load for 2027-2036.

- Resource retirements will be calculated based on resource age or other characteristic, as described for the first planning period of each scenario.
- Resource additions (except renewable resources) will be calculated based on known and planned additions for all scenarios.
- Imports and exports will be assumed to remain constant from the 2026 value through the second planning period.
- Dispatchable DR will be assumed to remain constant from the 2026 value through the second planning period.
- BTM PV is extrapolated beyond 2026 using a logarithmic trendline.

4.3.2 Deliverability

Resources can be modeled as Energy-only or Deliverable. The CAISO's TPP, for purposes of identifying needed policy-driven transmission additions, assumes that the renewable resource portfolios provided by the CPUC will require deliverability. Beyond that, however, in order to better allow for analysis of options for providing additional generic capacity, any additional resource will only be assumed to be Deliverable if it meets one of two criteria:

(1) Fits on the existing transmission and distribution system,[68] including minor upgrades,[69] or new transmission approved by both California ISO and CPUC, or

(2) It is a baseload or flexible resource.[70]

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[68] For this purpose, "fits" refers to the simple transmission assumptions listed on tab g – TxInputs of the RPS Calculator. Staff shall collaborate with the California ISO to update these transmission assumptions and apply them to the resource portfolios.

[69] Minor upgrades do not require a new right of way; other factors such as cost are not considered.

This assumption is only for study and planning purposes and does not prejudge any future CPUC decisions on transmission or resource approvals.

4.3.3 Price Methodologies

The same methodologies that were used in the 2014 LTPP proceeding shall be used for the 2016 LTPP proceeding.

Natural Gas

The CEC's Natural Gas Reference Case as put forward in the 2015 IEPR shall be used as the base for calculating natural gas prices. This price series was constructed to be consistent in baseline assumptions with the CED forecast and therefore the two are congruent for planning purposes.

Greenhouse Gas

The GHG price forecast as put forward in the 2015 IEPR Natural Gas Market Assessment: Outlook report, to be published in December 2015 by the CEC, shall be used as the base for calculating GHG prices.

Specified imports shall be subtracted from production cost modeling and accounted for. The remaining imports should be assigned annual GHG values based on an implied market heat rate or other value.

5 Planning Scenarios

5.1 2016 Planning Scenarios

The scenarios included herein will be prioritized based on the assumption that not all scenarios would be modeled, due to CAISO, IOU and other stakeholders' resource constraints. The priority given to each scenario will be decided upon after review of stakeholders' comments.

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[70] Flexibility currently does not have a standard definition, but a definition will be established either in this proceeding or in the Resource Adequacy proceedings (the current proceeding is R.11-10-023). Generally speaking, baseload resources are those that provide a constant power output, such as a nuclear plant while flexible resources are those that can respond to dispatch instructions. There is some overlap between these two categories, for example a baseload design combined cycle plant could provide some flexibility.

Unlike previous LTPP cycles, Commission staff does not propose a trajectory scenario for the 2016 LTPP. The recent approval of SB 350 has made the trajectory of State policy clear on a broad basis, but additional development on specific modeling inputs is needed before a true trajectory scenario can be developed. Instead, staff recommends adopting a Default Scenario that can be used to test modeling inputs and provide information for the development of a trajectory scenario at a later date. The Default Scenario, however, should not be regarded as representing the Commission staff assessment of the most probable California energy future; rather, the Default Scenario should be considered as analogous to a "control group" of assumptions reflecting existing programmatic and energy policies that we will use to compare and contrast the differences between it and the other scenarios. These differences, which in most scenarios result from a change in just one variable, are described below.

The ten proposed scenarios will use four different RPS portfolios[71] and will test the overall impact they have on GHG reduction and system reliability measures. The development and testing of the optimal RPS portfolio(s) will occur concurrently with the 2016 LTPP.

1. Default Scenario

What this scenario would help us study: The Default Scenario would serve as a control scenario that other scenarios could be compared and contrasted to while reflecting existing programmatic and energy policies, adjusted to reflect possible changes mandated by SB 350. The actual program changes and/or implementations necessary to reflect the SB 350 mandates are not available at this time.

Why this scenario is worthwhile to study: Other scenarios can be compared and contrasted to the Default Scenario, shedding light on the impacts that certain variables – while holding all (or most other) things constant – have on the procurement and/or transmission planning study results.

How this scenario would be created: The Default Scenario will incorporate key inputs and assumptions that would also be reflected in the other 2016 LTPP Scenarios (except

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[71] The four RPS portfolios are: a 33% portfolio that would be used in the 2016-17 TPP studies; a 50% by 2030 portfolio that is fully-deliverable, a 50% by 2030 portfolio that incorporates energy-only projects to reach the 50% RPS target; and a 50% by 2030 portfolio that incorporates 3000 MW of wind resources from Wyoming.

the Infrastructure Investment Scenario). For example, four key demand and supply side inputs and assumptions in the Default Scenario are:

1) The 1-in-2 year peak weather mid case 2015 IEPR demand forecast.
2) The doubling of the AAEE in the Mid-Baseline Mid-AAEE by 2030 interpolated to 2026.
3) A 43.3% RPS portfolio in 2026 (on path to 50% RPS by 2030).
4) Diablo Canyon Power Plant (DCPP) is offline in 2024/25.

Regarding the rest of the supply-side resource assumptions, this scenario would assume the default assumption for conventional resource additions, storage, dispatchable demand response programs and energy imports and exports. The Default Scenario would further assume a low level of renewable and hydro facility retirement and a mid-level retirement for other resource types while accounting for existing procurement authorizations. Supply-side CHP capacity would be updated based on the latest information contained in a database of CHP resources that has been compiled by Commission staff. The Default Scenario assumptions are listed in the Table 11 below.

Table 11: Default Scenario Assumptions

Category	Assumption
Test year	2026
Load	2015 IEPR Mid
AAEE	2 x 2014 IEPR[72] AAEE Mid, interpolated to 2026
RPS Percent	43.3% (on path to 50% by 2030)
RPS Mix	Balanced (possible high cost)
RPS Deliverability	Fully deliverable
DCPP	Retired in 2024/25
Local Frequency Constraints	4800 MW combined cycle + 365 MW hydro
Generation Fleet	CPUC NQC list
Gas Retirements	Retire at 40 years (unless under contract)
Gas Additions	CPUC/MUNI-approved contract
Behind-the-meter PV	2015 IEPR Mid
Demand Response	CPUC forecast
Combined Heat and Power	NQC + 2015 IEPR Mid

[72] The preliminary SB 350 AAEE calculation must be based on the 2014 IEPR CED forecast; see section 4.1.4.

Summary

Below, in Table 12, is a summary of how the nine scenarios described above would deviate from the Default Scenario, with specific input variables and RPS portfolios.

Table 12: Potential Scenarios For Modeling In The 2016 LTPP

#	Scenario	Variable change	RPS portfolio
2	Infrastructure Investment	Renewable portfolio	33% RPS
3	Interregional Transmission Planning Coordination	Modeling constraints on frequency	Default
4	Deliverability (Energy-Only)	Energy-only RPS	43.3% RPS, energy-only
5	Low Load	2015 IEPR low forecast (1 in 2)	Default
6	Renewables Providing Operational Flexibility	Modeling of renewables	Default
7	Out-of-state Wind	3000 MW of Wyoming wind	43.3% RPS, out-of-state
8	TOU Rate	Load curves	Default
9	Transportation Electrification	Electric Vehicle load (Commission staff forecast)	Default
10	High BTM PV	BTM PV load (Commission staff forecast)	Default

NOTE: "Commission staff forecast" indicates that staff would perform internal analysis in order to develop input variables.

2. Infrastructure Investment Scenario

What this scenario would help us study: This scenario would be provided to the CAISO as the base-case to be used in the 2016-17 Transmission Planning Process (TPP) studies.[73]

Why this scenario is worthwhile to study: The renewable resources portfolio plays an integral role when modeling the electric system. The CAISO and the CPUC have a memorandum of understanding under which the CPUC provides a renewable resource portfolio for CAISO to analyze in the CAISO's annual TPP. The TPP analyzes the

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[73] The CAISO authorizes new transmission infrastructure based on studies of the Base-Case scenario.

transmission system and determines the need for new transmission resources to ensure system reliability and meet policy goals (such as 50% RPS by 2030 target). This scenario updates critical operational variables of the transmission system but does not forecast an increase in renewable resources beyond the 33% goal used in previous trajectory scenarios.

Until the CPUC has fully analyzed alterative renewable portfolios and selected a preferred course of action for infrastructure investment enhancements, it would be inappropriate to plan significant transmission expansion investments to access increased renewable resources. If a fully-deliverable portfolio consisting of a RPS percentage greater than 33% is studied by the CAISO as part of its "base-case" TPP scenario, such a portfolio would likely result in a CAISO assessment indicating that new transmission capacity is needed to bring renewable energy, beyond the 33% RPS threshold, to market. We do not want to generate a renewable portfolio that might trigger new transmission investment until more information is available.

Similarly, a new 33% RPS portfolio generated by the updated RPS calculator would be based upon increasing customer generation and declining IEPR load forecasts and therefore could be based upon a lower RPS net short than the RPS portfolio used in the 2015-16 TPP. Such a portfolio might not support currently approved transmission projects that will be needed to reach 50% RPS goals. We do not want to generate a renewable portfolio which forces the CAISO to reexamine previously approved transmission investment decisions until more information is available.[74]

Submitting the Infrastructure Investment Scenario for the CAISO to study as part of the 2016-17 TPP therefore ensures that the CAISO study results would reflect known transmission needs, not transmission needs based on speculative renewable portfolios. On a practical level, transmission capacity exists to interconnect additional renewable projects without major new transmission expansion. Nevertheless, a new RPS portfolio – even one that models a 33% RPS target – could still lead to a CAISO finding that new transmission capacity is necessary if such portfolio is sufficiently different than the 33% RPS portfolios previously studied.

[74] As an additional point of consideration, it makes little sense to use constrained modeling resources to incorporate a new RPS portfolio into the TPP if the CPUC does not wish, at this time, to explore additional transmission policy projects. Available modeling resources should be used to explore more pressing grid issues.

How this scenario would be created: The Infrastructure Investment Scenario has a different RPS percentage than the other scenarios. This scenario would use the same RPS portfolio that was supplied by Commission staff to the CAISO for the 2015-16 TPP, the "33% 2025 Mid AAEE" trajectory portfolio,[75] without updates. Other variables such as load and retirement dates (but not the retirement dates of renewable resources) would be updated to match the Default Scenario.[76] As a result, the renewable GWh energy value contained in the Infrastructure Investment Scenario could exceed 33% of forecast demand, but will not be on a pathway to 50% RPS by 2030.

3. Interregional Transmission Planning Coordination Scenario

What this scenario would help us study: The CPUC would use this scenario to explore the impacts of improved interregional coordination, and even full integration, between the CAISO and neighboring balancing authorities.

Why this scenario is worthwhile to study: Electric grid coordination over a larger geographic area typically increases the diversity of both the load and the resources available to serve that load. Electric grid coordination also facilitates the transfer of excess renewable energy, which may materialize in some hours in one balancing authority, to other balancing authority areas where that energy can be utilized economically relative other load-serving options. If the CAISO eventually transforms into a regional entity beyond California, its larger footprint could change the reliability, economic, and even policy-related needs and opportunities in ways that impact CPUC-administered resource procurement programs. By proactively studying these implications, we can better understand the impacts of increased western electricity coordination under a 50% RPS and low-carbon grid future. Studying the effects of enhanced coordination in the 2016 LTPP would be timely, as several utilities in the West have recently announced their intention to participate in the CAISO's Energy Imbalance

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[75] See section "4.2.7 RPS Portfolios for the 2015-16 TPP" of "Attachment 2" (found here: PDF) from the "Assigned Commissioner's Ruling on updates to the Planning Assumptions and Scenarios for use in the 2014 Long-Term Procurement Plan and the California Independent System Operator's 2015-2016 Transmission Planning Process" (found here: PDF).

[76] As such, Diablo Canyon Power Plant (DCPP) should be modeled as being off-line by 2026 in the Infrastructure Investment Scenario. We assume that DCPP Unit 1 will be retired on November 2, 2024 and that Unit 2 will be retired on August 20, 2025, per the U.S. Energy Information Administration website: http://www.eia.gov/nuclear/state/california/

Market. In addition, PacifiCorp is considering fully integrating with the CAISO and participating in the full scope of the CAISO's activities (e.g., day-ahead scheduling and transmission planning). Moreover, SB 350 expresses the Legislature's intent for the CAISO's scope to expand beyond California to promote the development of more efficient western electricity markets, improving customers' access to those markets. Studying such a CAISO-expansion scenario would help us examine how to increase access to both renewable resources and to the markets that can consume excess renewable generation. This scenario would also enable us to test how to procure reliability services, such as frequency response, more efficiently from a larger and more diverse pool of resources.

How this scenario would be created: Modeling an expanded coordination scenario would involve decreasing or removing non-physical constraints on modeled energy imports to and exports from the current CAISO footprint, as well as more freely (with fewer constraints) optimizing modeled energy dispatch and procurement of ancillary services over a wider footprint. Electric system modeling might nevertheless still need to reflect some localized reliability needs, which must be reexamined under the new study scenario(s) representing a market paradigm of expanded coordination. One or more sensitivity scenarios could explore:

1. Alternative CAISO area frequency response commitment requirements besides 4800 MW combined cycle + 365 MW hydro;
2. Obtaining some of the within-area frequency response from nonconventional sources (this would be informed by the results of CAISO's frequency response studies);
3. Obtaining frequency response from a wider pool of resources in an expanded CAISO balancing authority area (consultation would be needed to determine what external areas should be assumed to join CAISO and how much of the aggregate frequency response obligation should be assumed to be met via which external resources); or
4. Obtaining frequency response from a wider pool of resources even without CAISO expansion, by purchasing frequency response capability from neighboring balancing authorities (i.e., purchasing from those balancing authorities or generators within those balancing authorities a commitment to provide upward dispatch in the event of western system post-event frequency decline [e.g., if two Palo Verde units go offline], thus substituting for some of the load-based responsibility for frequency response that CAISO would otherwise bear. The result would be that CAISO would not have to commit as many combined cycle MW for frequency response.)

4. Deliverability (Energy-Only) Scenario

What this scenario would help us study: The Deliverability (Energy-Only) Scenario for the 2016 LTPP would include a 43.3% RPS portfolio by 2026 that consists of some renewable resources that are "energy-only,"[77] enabling us to explore the optimality of such portfolio relative to one that is fully-deliverable.

Why this scenario is worthwhile to study: This portfolio would enable the CPUC and the CAISO to better understand how the existing transmission infrastructure can be optimized while still reaching 50% RPS by 2030. Current practice in California is that new resources are made fully-deliverable, providing resource adequacy value to the system.

The CAISO forecasts that there is sufficient transmission capacity on the system to reach the 33% RPS target; however, it is unclear whether there is sufficient transmission capacity to accommodate 50% RPS by 2030. Energy-only renewable resources could present a viable (and perhaps less expensive) alternative for reaching the State's GHG goals.

The RPS calculator (in comparing energy-only vs. fully deliverable futures) shows that energy-only can affect the geographic distribution of generic renewable resources across the state and across the WECC (e.g., it shifts resources toward areas where existing transmission capacity is available). In other words, energy-only resources could impact the need for new flexible resources, system resources, and transmission capacity. When compared and contrasted to the Default Scenario, the Deliverability (Energy-Only) Scenario would also shed light on congestion issues that the grid operator might face in the event that an energy-only path is chosen to reach the 50% RPS target.

How this scenario would be created: New renewable resources (mainly those that are forecasted to satisfy the 33% to 43.3% tranche of this portfolio) would be modeled as energy-only resources that do not receive a resource adequacy payment. The RPS portfolio used in the Deliverability (Energy-Only) Scenario would be created by running the new RPS calculator version 6.1a.

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[77] The energy from energy-only resources flows to load centers only if sufficient capacity exists on a given transmission line.

5. Low Load Scenario

What this scenario would help us study: The CPUC would use this scenario to evaluate the impact that a lower-than-forecasted load would have on resource needs.

Why this scenario is worthwhile to study: In the past, transmission and procurement planning decisions were based on peak summer weather conditions. Revising load forecasts downward, while holding all other variables constant, effectively increased the system's existing operating reserve margin. However, the recent focus on the system's operational flexibility needs has changed this resource-to-reserve margin dynamic, perhaps even inverting its relationship. Lower loads still reduce peak demand, but they also now have a tendency to contribute to over-generation conditions, which have emerged as a focal point of recent operational flexibility planning. A low-load scenario may now enable us to highlight the increased amount of over-generation, which in turn may reveal needs for more flexible resources to address that over-generation condition. By studying this scenario we would better understand the need for flexible resources under a low load forecast.

How this scenario would be created: This scenario would adopt the "low-demand" case from the CEC's IEPR forecast. The RPS portfolio incorporated in this scenario would be the default portfolio to better reflect the impacts of load being lower than forecast.

6. Renewables Providing Operational Flexibility Scenario

What this scenario would help us study: The CPUC would use this scenario to evaluate the system impacts of a flexible RPS fleet that can provide ramping up and/or down capacity (i.e. regulation, spinning reserves and load-following).

Why this scenario is worthwhile to study: Currently gas-fired electric generators are kept online so that the system operators can ramp these resources up or down in order to balance the system's electrical demand and supply. However, running gas-fired generators in order to balance the grid while reducing renewable output results in higher GHG emissions, which runs contrary to the State's RPS and GHG emission reduction targets. The Union of Concerned Scientists (UCS) recently found that reaching the 50% RPS target while utilizing zero or low GHG tools to provide operational flexibility (which include flexible operation of RPS generators) would reduce the electric sector's

GHGs by 20% relative to using existing "peaker" gas-fired resources for operational flexibility.[78] UCS's description of this more ideal electric system reliability paradigm could be realized by changing renewable procurement practices, modifying compensation to include other products besides kWh produced, requiring renewable generators to install control equipment, and by supporting/enabling the ability of renewable resources to participate in CAISO markets.

How this scenario would be created: In order to study the Renewables Providing Operational Flexibility Scenario, modeling conventions would need to reflect the assumption that renewable generators may also ramp up and/or down as needed to maintain reliability.

7. Out-of-state Wind Scenario

What this scenario would help us study: The CPUC would use the Out-of-state Wind Scenario to study the impact of additional out-of-state wind resources would have on CAISO's control area. It would not model any of the changes included in the Interregional Transmission Planning Coordination Scenario.

Why this scenario is worthwhile to study: This scenario would shed light on the costs and benefits of accessing out-of-state wind to reach the State's RPS and GHG goals. Wind generated in Wyoming has a different production profile than wind resources in California. This scenario would examine if access to these resources would reduce or increase over-generation and the need for flexibility resources. In addition, it would explore the amount (if any) of transmission infrastructure needed to deliver this resource to California.

How this scenario would be created: It would be modeled to reflect 3,000 MW of Southern Wyoming wind resources being deliverable to California. The RPS portfolio incorporated in this scenario would be produced by running the new RPS calculator version 6.1a.

8. TOU Rate Scenario

[78] Available online at: www.ucsusa.org/California50RPSanalysis.

What this scenario would help us study: The CPUC would utilize this scenario to consider the potential changes in the daily and seasonal load shapes resulting from significant changes in retail rates tariffs. Modeling these load shape changes would help us assess the potential impacts that retail rate changes have on costs, emissions, over-generation, and ramping needs in CAISO's control area. Retail rate changes that would be modeled include defaulting residential customers to TOU rates, residential rate tier compaction,[79] and shifting TOU price periods.

Why this scenario is worthwhile to study: Policies that modify daily and seasonal load shapes and shift electric demand to time periods in which abundant renewable energy production exists have the potential to lower costs, emissions, and over-generation concerns for grid operations, with minimal infrastructure investment. Policies that shift electric demand may also interact with other grid integration measures, such as providing additional incentive to procure energy storage or target energy efficiency measures at periods of the day when the cost of energy is high.

How this scenario would be created: The TOU Rate Scenario would be created by developing an 8760 hour load profile that is aligned with the 2015 IEPR peak and energy managed forecast. This load profile would be further adjusted to reflect the estimated impacts that the retail rate changes – specifically measures to default residential customers to TOU rates, redefine TOU price periods, and collapse residential rate tiers – have on the load profile. A supplemental analysis included in the 2015 IEPR[80] (which is not part of the IEPR base case or managed forecast) presents six scenarios of estimated impacts from various retail rate changes that are incremental to the 2013 IEPR vintage of the California forecast. We propose using "Scenario 5" as described in the 2015 IEPR supplemental analysis, which includes TOU price period changes recommended by the CAISO and "conceptual" rates proposed by Commission staff designed to accommodate high renewable resource penetration. The "Scenario 5" load profile adjustment would need to be updated and aligned with the 2015 IEPR vintage of the California peak and energy forecast, and further adjusted for AAEE and BTM PV impacts. The 8760 hour load profile would only be created for the target study year of 2026.

[79] Default TOU is scheduled for 2019. Tier compaction is ongoing, but should be completed in 2019.

[80] In a supplemental report, titled: "Joint Agency Staff Paper on Time-Of-Use Load Impacts."

9. Transportation Electrification Scenario

What this scenario would help us study: The Transportation Electrification Scenario would enable the CPUC to consider the impact that the electrification of California's transportation sector would have on CAISO's control area.

Why this scenario is worthwhile to study: Future CPUC-directed programs that encourage the utilization of electricity to power the transportation sector, pursuant to SB 350, will potentially have an enormous impact on GHG emissions, reliability, flexibility, and costs. The IEPR demand forecast has a well-reasoned estimate of transportation electrification load, but this area has a high degree of uncertainty, and studying alternate futures would provide more information for decision makers to consider. Studying varied levels of electrified transportation could provide valuable information to the CPUC and the grid operators regarding load shape, over-generation conditions, and related local reliability concerns associated with varying transportation electrification penetration levels and operational characteristics.

How this scenario would be created: The assumptions regarding transportation electrification will be updated in the final IEPR forecast. Commission staff would consider the final CEC assumptions regarding electric vehicle penetration and the amount of electrification assumed for other transportation segments that are accounted for in the final IEPR forecast. Staff would also account for the associated technological and adoption assumptions embedded in the forecast when considering the merits of creating a lower (or higher) electrification scenario. Such a scenario would incorporate the potential growth in the non-light duty vehicle sector, including medium-duty and heavy-duty vehicles, vessels, trains, boats, or other equipment that could be studied in the 2016 LTPP.

10. High BTM PV Scenario

What this scenario would help us study: In the High BTM PV Scenario the CPUC would consider the impacts that a higher amount of BTM PV—relative to what is included in the mid-case IEPR demand forecast—would have on costs, emissions, over-generation, and operational flexibility in CAISO's control area.

Why this scenario is worthwhile to study: BTM PV resources have the potential to decrease the overall load served in the CAISO service territory, thereby reducing the need to procure electric resources, including utility-scale renewable resources. At the same time, increasing amounts of PV could escalate over-generation conditions and create (or exacerbate) operational flexibility issues.

How this scenario would be created: The High BTM PV Scenario would be created by: 1) subtracting the mid-PV capacity embedded in the mid-case IEPR demand forecast from the high-PV capacity embedded in the low-case IEPR demand forecast, and 2) adding this capacity differential to the mid-PV capacity embedded in the mid-case IEPR demand forecast. This calculation would be based on CEC-provided data. It would be adjusted for transmission and distribution loss avoidance and would include the expected MW production at system peak and the expected GWh energy production from BTM PV resources for each year of the 2016-2026 timeframe being studied.

Appendix A-1

		Mid AAEE Savings, Extrapolated to 2030 by LSE															
		<--From The 2014 IEPR Forecast										Extrapolated From 2014 IEPR Forecast based on "Average Annual Growth Rates"-->					
	Agency	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	RPS Calculator Load Category
1	Calaveras Public Power Agency																Other CAISO
2	Central Valley Project																Non CAISO
3	City of Alameda																Other CAISO
4	City of Biggs																Other CAISO
5	City of Gridley																Other CAISO
6	City of Healdsburg																Other CAISO
7	City of Hercules																Other CAISO
8	City of Lodi																Other CAISO
9	City of Lompoc																Other CAISO
10	City of Palo Alto																Other CAISO
11	City of Redding																Non CAISO
12	City of Roseville																Non CAISO
13	City of San Francisco																Other CAISO
14	City of Shasta Lake																Non CAISO
15	City of Ukiah																Other CAISO
16	Island Energy/Pittsburg																Other CAISO
17	Lassen Municipal Utility District																Other CAISO
18	Merced Irrigation District																Non CAISO
19	Modesto Irrigation District																Non CAISO
20	Pacific Gas and Electric Company (Bundled)	1,586	2,353	3,045	3,809	4,491	5,220	5,991	6,819	7,649	8,579	9,406	10,244	11,093	11,953	12,825	PG&E
21	Pacific Gas and Electric Company (Direct Access)	199	290	371	456	530	607	687	772	855	947	1,031	1,115	1,199	1,283	1,367	Other CAISO
22	Pacific Gas and Electric Company (Marin Clean Energy (	34	49	63	77	89	102	115	129	143	158	171	184	197	210	223	Other CAISO
23	Pacific Gas and Electric Company (Sonoma Clean Powe	37	54	69	86	100	114	130	146	162	180	222	271	331	401	484	Other CAISO
24	Plumas-Sierra Rural Electric Cooperation																Other CAISO
25	Port of Oakland																Other CAISO
26	Port of Stockton																Other CAISO
27	Silicon Valley Power																Other CAISO
28	Tuolumne County Public Power Agency																Other CAISO
29	Turlock Irrigation District																Non CAISO
30																	Total
31	Sacramento Municipal Utility District																Non CAISO
32	Anza Electric Cooperative, Inc.																Other CAISO
33	Azusa Light & Water																Other CAISO
34	Bear Valley Electric Service																Other CAISO
35	City of Anaheim																Other CAISO
36	City of Banning																Other CAISO
37	City of Colton																Other CAISO
38	City of Corona																Other CAISO
39	City of Rancho Cucamonga																Other CAISO
40	City of Riverside																Other CAISO
41	City of Vernon																Other CAISO
42	Metropolitan Water District																Non CAISO
43	Moreno Valley Utilities																Other CAISO
44	Southern California Edison Company (Bundled)	1,952	2,864	3,605	4,360	5,042	5,775	6,519	7,335	8,167	9,090	9,970	10,863	11,768	12,686	13,616	SCE
45	Southern California Edison Company (Direct Access)	307	444	553	660	752	850	946	1,051	1,157	1,272	1,378	1,483	1,587	1,690	1,792	Other CAISO
46	Valley Electric Association, Inc.																Other CAISO
47	Victorville Municipal																Other CAISO
48																	Total
49	Los Angeles Department of Water and Power																Non CAISO
50	City of Burbank																Non CAISO
51	City of Glendale																Non CAISO
52																	Total
53	City of Pasadena																Other CAISO
54	Department of Water Resources																Non CAISO
55	San Diego Gas and Electric Company (Bundled)	413	609	764	943	1,103	1,280	1,468	1,667	1,866	2,089	2,292	2,496	2,704	2,913	3,126	SDG&E
56	San Diego Gas and Electric Company (Direct Access)	85	126	157	191	220	253	286	321	356	394	428	463	497	531	565	Other CAISO
57																	Total
58	Imperial Irrigation District																Non CAISO
59	California Pacific Electric Company, LLC																Non CAISO
60	City of Needles																Non CAISO
61	Kirkwood Meadows Public Utility District																Non CAISO
62	PacifiCorp																Non CAISO
63	Surprise Valley Electrification Corporation																Non CAISO
64	Truckee-Donner Public Utility District																Non CAISO

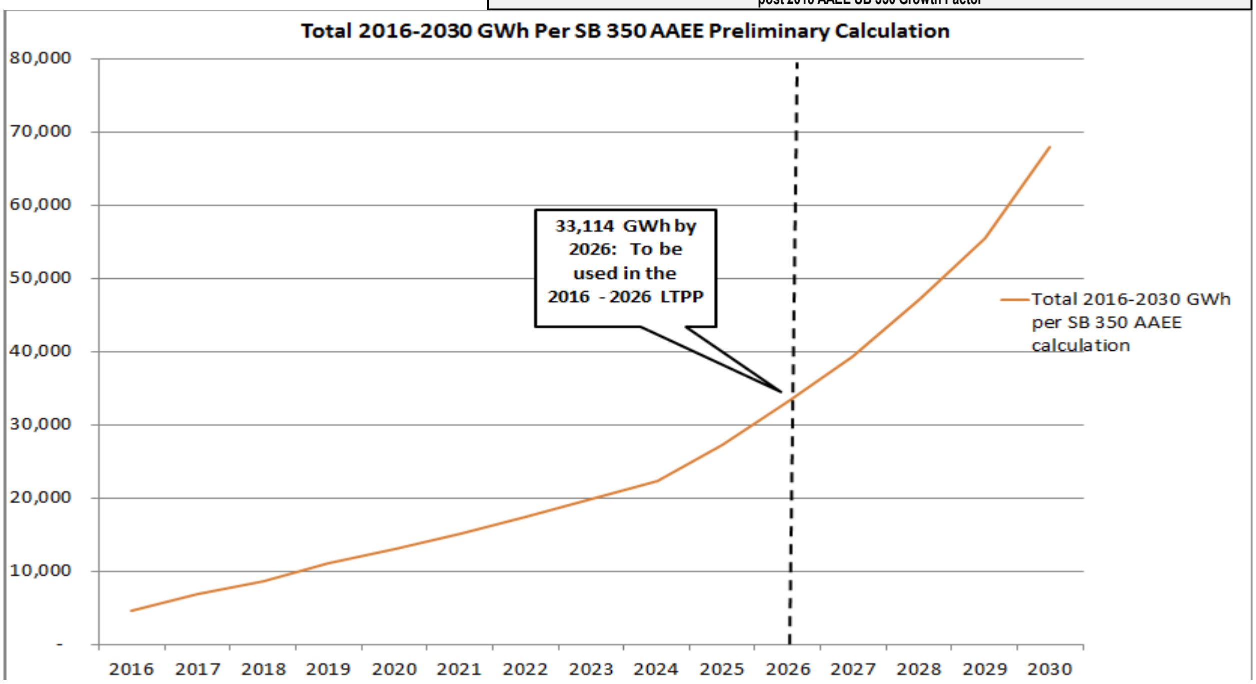
Appendix A-2

	Mid AAEE Savings Adjusted For SB 350 AAEE Growth Factors, Extrapolated to 2030 by LSE																
		Actual 2014 IEPR Forecast			<--Adjusted For SB 350 AAEE Growth Factors Based On The 2014 IEPR Forecast							Adjusted For SB 350 AAEE Growth Factors Based on Extrapolated IEPR Forecast-->					
	Agency	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	RPS Calculator Load Category
1	Calaveras Public Power Agency																Other CAISO
2	Central Valley Project																Non CAISO
3	City of Alameda																Other CAISO
4	City of Biggs																Other CAISO
5	City of Gridley																Other CAISO
6	City of Healdsburg																Other CAISO
7	City of Hercules																Other CAISO
8	City of Lodi																Other CAISO
9	City of Lompoc																Other CAISO
10	City of Palo Alto																Other CAISO
11	City of Redding																Non CAISO
12	City of Roseville																Non CAISO
13	City of San Francisco																Other CAISO
14	City of Shasta Lake																Non CAISO
15	City of Ukiah																Other CAISO
16	Island Energy/Pittsburg																Other CAISO
17	Lassen Municipal Utility District																Other CAISO
18	Merced Irrigation District																Non CAISO
19	Modesto Irrigation District																Non CAISO
20	Pacific Gas and Electric Company (Bundled)	1,586	2,353	3,045	3,999	4,760	5,585	6,470	7,433	8,414	10,294	12,510	14,854	17,750	20,919	25,649	PG&E
21	Pacific Gas and Electric Company (Direct Access)	199	290	371	479	562	650	742	841	941	1,136	1,371	1,617	1,918	2,245	2,734	Other CAISO
22	(Marin Clean Energy CCA)	34	49	63	81	94	109	124	141	157	189	227	267	316	368	446	Other CAISO
23	(Sonoma Clean Power CCA)	37	54	69	90	106	122	140	159	178	215	295	394	529	702	968	Other CAISO
24	Plumas-Sierra Rural Electric Cooperation																Other CAISO
25	Port of Oakland																Other CAISO
26	Port of Stockton																Other CAISO
27	Silicon Valley Power																Other CAISO
28	Tuolumne County Public Power Agency																Other CAISO
29	Turlock Irrigation District																Non CAISO
30																	Total
31	Sacramento Municipal Utility District																Non CAISO
32	Anza Electric Cooperative, Inc.																Other CAISO
33	Azusa Light & Water																Other CAISO
34	Bear Valley Electric Service																Other CAISO
35	City of Anaheim																Other CAISO
36	City of Banning																Other CAISO
37	City of Colton																Other CAISO
38	City of Corona																Other CAISO
39	City of Rancho Cucamonga																Other CAISO
40	City of Riverside																Other CAISO
41	City of Vernon																Other CAISO
42	Metropolitan Water District																Non CAISO
43	Moreno Valley Utilities																Other CAISO
44	Southern California Edison Company (Bundled)	1,952	2,864	3,605	4,578	5,344	6,179	7,041	7,995	8,983	10,908	13,261	15,751	18,829	22,200	27,232	SCE
45	Southern California Edison Company (Direct Access)	307	444	553	693	797	909	1,022	1,146	1,272	1,526	1,833	2,151	2,540	2,958	3,584	Other CAISO
46	Valley Electric Association, Inc.																Other CAISO
47	Victorville Municipal																Other CAISO
48																	Total
49	Los Angeles Department of Water and Power																Non CAISO
50	City of Burbank																Non CAISO
51	City of Glendale																Non CAISO
52																	Total
53	City of Pasadena																Other CAISO
54	Department of Water Resources																Non CAISO
55	San Diego Gas and Electric Company (Bundled)	413	609	764	990	1,169	1,370	1,586	1,817	2,053	2,507	3,048	3,620	4,326	5,098	6,252	SDG&E
56	San Diego Gas and Electric Company (Direct Access)	85	126	157	201	234	270	309	350	391	472	569	671	795	929	1,130	Other CAISO
57																	Total
58	Imperial Irrigation District																Non CAISO
59	California Pacific Electric Company, LLC																Non CAISO
60	City of Needles																Non CAISO
61	Kirkwood Meadows Public Utility District																Non CAISO
62	PacifiCorp																Non CAISO
63	Surprise Valley Electrification Corporation																Non CAISO
64	Truckee-Donner Public Utility District																Non CAISO
					1.05	1.06	1.07	1.08	1.09	1.1	1.2	1.33	1.45	1.6	1.75	2.0	
					post 2018 AAEE SB 350 Growth Factor												

Appendix A-3

	Mid AAEE Savings, Extrapolated to 2030 by LSE														
	<--2014 IEPR Forecast										Extrapolated From 2014 IEPR Forecast based on "Average Annual Growth Rates"-->				
Category	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
PG&E	1,586	2,353	3,045	3,809	4,491	5,220	5,991	6,819	7,649	8,579	9,406	10,244	11,093	11,953	12,825
SCE	1,952	2,864	3,605	4,360	5,042	5,775	6,519	7,335	8,167	9,090	9,970	10,863	11,768	12,686	13,616
SDG&E	413	609	764	943	1,103	1,280	1,468	1,667	1,866	2,089	2,292	2,496	2,704	2,913	3,126
Other CAISO	661	964	1,213	1,470	1,691	1,926	2,164	2,419	2,672	2,949	3,229	3,516	3,811	4,115	4,431
Total 2016-2030 AAEE embedded in mid-AAEE forecast & extrapolated in 2026-2030	4,613	6,789	8,628	10,581	12,327	14,200	16,142	18,240	20,354	22,707	24,898	27,120	29,376	31,668	33,997

	Mid AAEE Savings Adjusted For SB 350 AAEE Growth Factors, Extrapolated to 2030 by LSE														
				<--Adjusted For SB 350 AAEE Growth Factors Based On The 2014 IEPR Forecast							2014 IEPR Forecast Extrapolated-->				
Category	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
PG&E	1,586	2,353	3,045	3,999	4,760	5,585	6,470	7,433	8,414	10,294	12,510	14,854	17,750	20,919	25,649
SCE	1,952	2,864	3,605	4,578	5,344	6,179	7,041	7,995	8,983	10,908	13,261	15,751	18,829	22,200	27,232
SDG&E	413	609	764	990	1,169	1,370	1,586	1,817	2,053	2,507	3,048	3,620	4,326	5,098	6,252
Other CAISO	661	964	1,213	1,543	1,793	2,061	2,337	2,637	2,939	3,539	4,295	5,098	6,097	7,202	8,862
Total 2016-2030 GWh per SB 350 AAEE calculation	4,613	6,789	8,628	11,110	13,066	15,194	17,434	19,881	22,390	27,249	33,114	39,324	47,001	55,418	67,995
post 2018 AAEE SB 350 Growth Factor				1.05	1.06	1.07	1.08	1.09	1.1	1.2	1.33	1.45	1.6	1.75	2.0



Appendix A-4

Form 1.1c - Statewide

California Energy Demand Updated Forecast, 2015 - 2025, Mid Demand Baseline Case, No AAEE Savings

Electricity Deliveries to End Users by Agency (GWh)

		<--2014 IEPR Forecast (2016 - 2025 Shown Here; Original Forecast Is From 2013 to 2025)										Extrapolated From 2014 IEPR Forecast based on "Average Annual Growth Rates"-->				
	Agency	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
1	Calaveras Public Power Agency															
2	Central Valley Project															
3	City of Alameda															
4	City of Biggs															
5	City of Gridley															
6	City of Healdsburg															
7	City of Hercules															
8	City of Lodi															
9	City of Lompoc															
10	City of Palo Alto															
11	City of Redding															
12	City of Roseville															
13	City of San Francisco															
14	City of Shasta Lake															
15	City of Ukiah															
16	Island Energy/Pittsburg															
17	Lassen Municipal Utility District															
18	Merced Irrigation District															
19	Modesto Irrigation District															
20	Pacific Gas and Electric Company (Bundled)	76,008	77,136	78,167	79,430	80,653	81,805	83,033	84,133	85,165	86,270	87,242	88,225	89,218	90,223	91,240
21	Pacific Gas and Electric Company (Direct Access)	9,520	9,520	9,520	9,520	9,520	9,520	9,520	9,520	9,520	9,520	9,561	9,601	9,642	9,683	9,725
22	Pacific Gas and Electric Company (Marin Clean Ene	1,614	1,611	1,607	1,604	1,601	1,598	1,594	1,591	1,588	1,585	1,585	1,586	1,586	1,587	1,587
23	Pacific Gas and Electric Company (Sonoma Clean P	1,774	1,777	1,781	1,784	1,788	1,791	1,795	1,799	1,802	1,806	2,055	2,338	2,661	3,027	3,445
24	Plumas-Sierra Rural Electric Cooperation															
25	Port of Oakland															
26	Port of Stockton															
27	Silicon Valley Power															
28	Tuolumne County Public Power Agency															
29	Turlock Irrigation District															
30																
31	Sacramento Municipal Utility District															
32	Anza Electric Cooperative, Inc.															
33	Azusa Light & Water															
34	Bear Valley Electric Service															
35	City of Anaheim															
36	City of Banning															
37	City of Colton															
38	City of Corona															
39	City of Rancho Cucamonga															
40	City of Riverside															
41	City of Vernon															
42	Metropolitan Water District															
43	Moreno Valley Utilities															
44	Southern California Edison Company (Bundled)	74,536	75,484	76,327	77,390	78,484	79,577	80,664	81,704	82,677	83,704	84,730	85,769	86,820	87,885	88,962
45	Southern California Edison Company (Direct Access	11,710	11,710	11,710	11,710	11,710	11,710	11,710	11,710	11,710	11,710	11,710	11,710	11,710	11,710	11,710
46	Valley Electric Association, Inc.															
47	Victorville Municipal															
48																
49	Los Angeles Department of Water and Power															
50	City of Burbank															
51	City of Glendale															
52																
53	City of Pasadena															
54	Department of Water Resources															
55	San Diego Gas and Electric Company (Bundled)	16,859	17,087	17,297	17,591	17,829	18,052	18,281	18,486	18,692	18,907	19,126	19,347	19,570	19,797	20,026
56	San Diego Gas and Electric Company (Direct Acces	3,482	3,529	3,562	3,562	3,562	3,562	3,562	3,562	3,562	3,562	3,573	3,584	3,596	3,607	3,618
57																
58	Imperial Irrigation District															
59	California Pacific Electric Company, LLC															
60	City of Needles															
61	Kirkwood Meadows Public Utility District															
62	PacifiCorp															
63	Surprise Valley Electrification Corporation															
64	Truckee-Donner Public Utility District															
65	Total 2014 IEPR Load of LSEs in CAISO's Service Territory	195,502	197,854	199,971	202,591	205,147	207,615	210,159	212,505	214,716	217,064	219,582	222,160	224,804	227,519	230,313
66	Total 2016-2030 GWh per SB 350 AAEE calculation	4,613	6,789	8,628	11,110	13,066	15,194	17,434	19,881	22,390	27,249	33,114	39,324	47,001	55,418	67,995
67	SB 350 Yearly GWh, As A Percentage Of Load Growth With No AAEE	**2.36%**	**3.43%**	**4.31%**	**5.48%**	**6.37%**	**7.32%**	**8.30%**	**9.36%**	**10.43%**	**12.55%**	**15.08%**	**17.70%**	**20.91%**	**24.36%**	**29.52%**
					1.05	**1.06**	**1.07**	**1.08**	**1.09**	**1.1**	**1.2**	**1.33**	**1.45**	**1.6**	**1.75**	**2.0**
					post 2018 AAEE SB 350 Growth Factor											

(END OF ATTACHMENT)